devon

2002 Annual Report

A FIRM FOUNDATION

CONTENTS

Devon Energy Corporation is engaged in oil and gas exploration, production and property acquisitions. Devon ranks among the top-five U.S.-based independent oil and gas producers 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.

Annual Report Theme
"A Firm Foundation For The Future" was inspired by three of more than 900 entries from employees in Devon's annual report theme contest. The winning entries were submitted by Cristy Harrison in Houston, Debbie Little in Oklahoma City and Linda Whelan in Calgary.

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 will be furnished upon request to the company.

FOR THE FUTURE

Devon's foundation for the future is supported by two vital elements: the strength of our assets and the excellence of our employees.

Featured employees clockwise, from upper left: Huy Tran, Oklahoma City; Paula Kupchak, Calgary; Cassey Jones and John Walker, Bridgeport; and Eveline Chartier, Calgary.

DEAR FELLOW SHAREHOLDERS

2002 will undoubtedly be remembered as a year of extraordinary achievement for Devon. We drove total oil and gas production to 188 million equivalent barrels, an all-time record. We successfully completed 1,599 oil and gas wells and a major acquisition. These activities replaced 278% of the year's production with new reserves at a cost of $7.18 per equivalent barrel. Total revenues, total assets and shareholders' equity all reached new highs. Although not a record, net earnings also increased in 2002, to $104 million.

J. Larry Nichols

Building With Acquisitions

The results for 2002 reflect the impact of two acquisitions that nearly doubled the size of the company: Mitchell Energy and Anderson Exploration. At this time a year ago, these acquisitions had only recently been completed. Since then, the three organizations have been melded into one.

On October 15, 2001, Devon completed the purchase of Canadian producer, Anderson. The marriage of Anderson's assets with Devon's Canadian operations creates a formidable Canadian independent. Devon now has a leading position in all of the major producing regions in the Western Canadian Sedimentary Basin. Furthermore, our 11 million net undeveloped acres in Canada provide Devon with one of the largest inventories of exploratory acreage in that country.

We are gratified by the many former Anderson employees who chose to join with us to build upon Devon's foundation in Canada. During 2002, under the leadership of Devon Senior Vice President, John Richels, our Canadian employees enthusiastically joined together to blend their cultures and their operations. Remarkably, this integration was achieved without losing momentum in last year's winter drilling program. In the period from mid-December 2001 to mid-March 2002, we drilled 276 wells with an 88% success rate—an outstanding performance by any standard.

Simultaneously, Devon's U.S. employees were busy integrating the operations of Mitchell. The development of Mitchell's crown jewel, the Barnett Shale gas properties in north Texas, progressed flawlessly during the transition. In the 11 months of 2002 following the close of the Mitchell acquisition, production from the Barnett Shale climbed 40% to 500 million equivalent cubic feet of gas per day. To accommodate this growth, we completed a significant expansion of our Bridgeport gas plant. Furthermore, the drilling efficiencies and well completion improvements initiated by Mitchell continue under the Devon flag. Over the last year we have further reduced the cost and time required to drill a Barnett Shale well. These savings reflect the economies available to a larger, stronger company as well as the professionalism and enthusiasm of the Mitchell employees who joined Devon.

Successfully integrating Anderson and Mitchell while maintaining focus on our day-to-day operations presented an array of challenges across the organization. Devon's staff, old and new, responded with dedication and determination. It's clear the acquisitions of Mitchell and Anderson added not only an abundance of high quality oil and gas properties, but a wealth of human talent as well. I welcome each of these valued new employees to the Devon family.

Sharpening our Focus

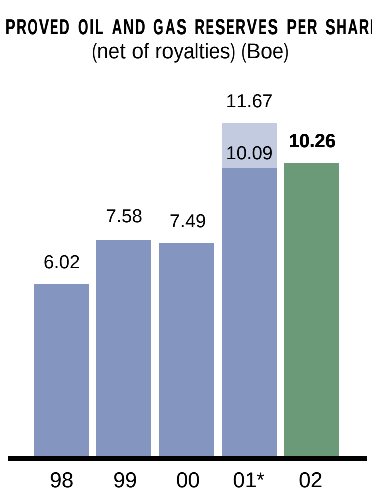
In addition to integrating the high quality oil and gas properties of Anderson and Mitchell during 2002, we significantly improved the focus of our operations. We completed a thorough review of all of the combined company's properties. We divested those with high operating costs, limited growth potential and those not significant to a company of Devon's new size. In total, we generated sales proceeds of $1.3 billion after tax, exceeding our expectations. More importantly, the sale of these properties leaves Devon with a focused, highly profitable asset base with abundant opportunities for growth.

A Firm Financial Foundation

In the acquisitions of Anderson and Mitchell, Devon issued approximately 30 million new common shares and took on $6.7 billion in incremental debt. In March of 2002, we extended our debt maturity schedule with the issuance of $1 billion of 30-year notes. In addition, following the Mitchell acquisition, we used the proceeds from property divestitures and cash on hand to reduce long-term debt by $1.3 billion. The average after-tax interest rate on our remaining debt is very low, about 3%. As a result, Devon enters 2003 with considerable financial strength and flexibility. Aided by the strong oil and gas prices we are currently experiencing, we are generating significant cash flow over and above our expected capital requirements. We have designated these funds to reduce debt and further fortify our balance sheet.

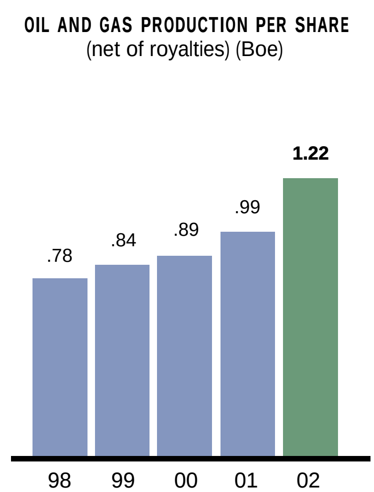
Investing for the Long Run

In 2002, our investments in drilling and production facilities totaled $1.6 billion—the largest capital budget in our history. With the successful completion of 1,599 oil and gas wells, we increased production from retained properties by four million equivalent barrels. In addition to the $1.3 billion that generated this near-term production growth, we invested approximately $300 million in longer-term, high-potential projects. These longer-term investments generated two notable drilling successes during 2002. Tuk M-18 in Canada's Mackenzie Delta and Cascade in the deepwater Gulf of Mexico each promise significant future reserve additions.



Since 1998, Devon has increased reserves per share by 70%...

* 2001 reserves include 1.58 Boe per share attributable to properties divested in 2002.



...and production per share by 56%.

In 2003, Devon will invest about $370 million on long-term projects spread across a broad geographic spectrum. In north Texas, we are exploring outside the core area in an attempt to extend the Barnett Shale play. Early results from these wells are very encouraging. In 2002, we leveraged our exposure to the deepwater Gulf of Mexico through a multi-well joint venture with ChevronTexaco. We expect to continue drilling exploratory wells during 2003 in this partnership. Also in the deepwater Gulf, we expect to drill a follow-up to our Cascade discovery later this year. Outside North America, Devon has an exploratory well planned for 2003 offshore Ghana in West Africa. We are also prospecting across the Atlantic from Africa in waters offshore Brazil. While these projects cannot impact production or earnings in the near-term, they represent the foundation for an attractive longer-term growth profile.

A Firm Foundation for the Future

As one of the largest natural gas producers in North America, Devon is positioned to reap the rewards of today's high natural gas prices. But to sustain Devon's track record of success, we must look beyond today and plan for the longer term. Our recently announced merger with Ocean Energy is an opportunity to do just that. Ocean brings to Devon significant near-term growth projects, a large inventory of high-impact exploration projects and a wealth of talented employees. The combined company will benefit from a better growth profile, a larger, higher-quality exploration inventory and superior financial strength.

As I look ahead in 2003, I am more optimistic about Devon's future than ever before. We have an abundance of visible, low-risk growth opportunities from our portfolio of North American properties. We have longer-term growth opportunities spanning from the Arctic Circle's Mackenzie Delta to the waters offshore West Africa. And we are blessed with the people and financial strength to capture these opportunities. Devon truly has established a firm foundation for the future.

J. Larry Nichols
CHAIRMAN, PRESIDENT AND CHIEF EXECUTIVE OFFICER
April 11, 2003

FIVE-YEAR HIGHLIGHTS

Devon's acquisition of Mitchell Energy on January 24, 2002, was recorded using the purchase method of accounting. Therefore, the information presented below includes Mitchell's results from January 24 through December 31, 2002, only.

YEAR ENDED DECEMBER 31,		1998	1999	2000	2001	2002	LAST YEAR CHANGE
FINANCIAL DATA (1) (Millions, except per share data)							
Total revenues (2)	$	604	1,140	2,587	2,864	4,316	51%
Operating costs and expenses	$	861	1,309	1,431	2,672	3,775	41%
Earnings from operations	$	(257)	(169)	1,156	192	541	182%
Other expenses	$	47	99	118	164	675	312%
Total income tax expense (benefit)	$	(103)	(75)	377	5	(193)	NM
Net earnings (loss) from continuing operations	$	(201)	(193)	661	23	59	157%
Net results of discontinued operations	$	(35)	39	69	31	45	45%
Net earnings (loss) applicable to common shareholders	$	(236)	(158)	720	93	94	114%
Net earnings (loss) per share:							
Basic	$	(3.32)	(1.68)	5.66	0.73	0.61	(16%)
Diluted	$	(3.32)	(1.68)	5.50	0.72	0.61	(15%)
Weighted average common shares outstanding:							
Basic		71	94	127	128	155	21%
Diluted		77	99	132	130	156	20%
Operating cash flow from continuing operations	$	308	452	1,479	1,776	1,726	(3%)
Operating cash flow from discontinued operations	$	22	87	110	134	28	(79%)
Net cash provided by operating activities	$	330	539	1,589	1,910	1,754	(8%)
Cash dividends per common share (3)	$	0.10	0.14	0.17	0.20	0.20	-
DECEMBER 31,		**1998**	**1999**	**2000**	**2001**	**2002**	**LAST YEAR CHANGE**
Total assets	$	1,931	6,096	6,860	13,184	16,225	23%
Debentures exchangeable into shares of ChevronTexaco Corporation common stock (4)	$	-	760	760	649	662	2%
Other long-term debt (5)	$	885	1,656	1,289	5,940	6,900	16%
Stockholders' equity	$	750	2,521	3,277	3,259	4,653	43%
Working capital	$	(29)	85	251	435	22	(95%)
PROPERTY DATA (1)							
Proved reserves (Net of royalties)							
Oil (MMBbls)		166	439	406	527	444	(16%)
Gas (Bcf)		1,440	2,785	3,045	5,024	5,836	16%
Natural gas liquids (MMBbls)		21	55	50	108	192	78%
Total (MMBoe) (6)		427	958	963	1,472	1,609	9%
10% present value before income taxes (Millions)	$	1,375	5,316	17,075	6,687	15,307	129%
10% present value after income taxes (Millions)	$	1,321	4,465	12,065	5,015	10,365	107%
YEAR ENDED DECEMBER 31,		**1998**	**1999**	**2000**	**2001**	**2002**	**LAST YEAR CHANGE**
Production (Net of royalties)							
Oil (MMBbls)		20	25	37	36	42	17%
Gas (Bcf)		189	295	417	489	761	56%
Natural gas liquids (MMBbls)		3	5	7	8	19	138%
Total (MMBoe) (6)		55	79	113	126	188	50%

(1) All of the years shown exclude results from Devon's operations in Indonesia, Argentina and Egypt that were discontinued in 2002. Data has also been reclassified 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. Revenues, expenses and production in 2002 include only eleven and one-fourth months attributable to the Mitchell acquisition; in 2001 include only two and one-half months attributable to the Anderson 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 1998 through 2002 are not representative of the actual amounts paid by Devon because of mergers accounted for as poolings. For the years 1998 through 2000, Devon's historical cash dividends per share were $0.20 in each year.
(4) Debentures exchangeable into seven million shares of ChevronTexaco common stock beneficially owned by Devon.
(5) Includes preferred securities of subsidiary trust of $149 million in 1998.
(6) Gas converted to oil at the ratio of 6 Mcf:1 Bbl. Natural gas liquids converted to oil at the ratio of 1Bbl:1Bbl.
NM Not a meaningful number.

Devon drills this exploratory well in Canada's Mackenzie Delta.
Drilling is limited to the winter months when the ground is frozen and can accommodate heavy equipment.

"As a Devon field employee in Canada, I work with one of the largest and highest quality property bases in this country. Our assets range from dependable, long-lived oil properties in central Alberta to high-impact exploration opportunities within the Arctic Circle."

STAFFORD WILSON – BURMIS, ALBERTA

EXECUTIVE Q&A

Devon completed five large mergers and acquisitions over the last five years and has recently agreed to merge with Ocean Energy. Can we expect this process to continue?

Larry Nichols, Chairman, President and CEO:

Historically, the North American oil and gas industry was far too fragmented for optimal efficiency. The consolidation that has been under way over the last 15 years has yielded fewer companies with better access to capital, better access to technology and greater economies of scale. Devon's shareholders have benefited from our participation in this consolidation. Devon has emerged as one of the largest and most efficient oil and gas producers in North America. Following the completion of our merger with Ocean, we will also have improved internal growth prospects and the financial strength to pursue both drilling and acquisitions. We will continue to evaluate potential mergers and acquisitions and are prepared to act should the right opportunity become available.

Devon repaid $1.3 billion in debt in 2002. Are you comfortable with current debt levels or can we expect further repayments this year?

Brian Jennings, Senior Vice President – Corporate Development:

Maintaining a strong balance sheet and a high degree of financial flexibility has always been a high priority for Devon. This allows us to utilize our balance sheet to seize growth opportunities when they become available. In late 2001 and early 2002, we elected to increase long-term debt to capture the extraordinary potential we saw in the Anderson and Mitchell acquisitions. We planned on using the proceeds from the sale of non-core properties and cash generated from operations to reduce indebtedness to levels more in line with our historic norms. With the progress we made in 2002, we were well on our way to this goal by year-end. Thus far in 2003, Devon is generating cash flow well in excess of our capital needs. This is allowing us to accumulate significant cash balances that we are earmarking for further debt repayment.

Devon invested $1.5 billion in exploration and development last year but failed to replace 100% of production with drilling. Do you expect this to improve in the future?

Mike Lacey, Senior Vice President – Exploration and Production:

Yes. While it is correct that we replaced only about 75% of our production with the drill bit in 2002, that doesn't really tell the whole story. In addition to the 142 million equivalent barrels of reserves that we recorded as additions during 2002, Devon made significant investments in longer-term, high-impact projects intended to add reserves and production in future years. The fruits of the $300 million plus we invested in 2002 for long-term growth include two successful high-impact wells that are not yet reflected in our reserves. We expect these wells, the Tuk M-18 in the Mackenzie Delta and the Cascade well in the deepwater Gulf of Mexico, to deliver significant reserve additions in the future.

While directing capital to these longer-term investments negatively impacts our reported finding costs and reserve replacement over the short run, it is projects like this that are expected to fuel Devon's growth and lower our finding costs over the long run.

A number of high profile companies have been accused of reporting irregularities. How can we be sure Devon is conducting its business ethically?

Bill Vaughn, Senior Vice President – Finance:

It is Devon's policy to adhere to the highest ethical standards. This policy applies not only to accounting, but extends to all of our business practices. Devon rigorously strives to strictly comply with all regulations in every place that we do business. In the area of securities regulation, we welcome effective regulatory efforts to provide a level playing field for all investors and strongly support these efforts. Should our employees encounter any evidence of ethical misconduct, they are encouraged to report the situation and we pledge to respond promptly.

Devon has discovered significant natural gas reserves in Canada's far north. When do you believe that gas will be brought to market?

John Richels, Senior Vice President – Canadian Division:

The Mackenzie Delta and Beaufort Sea have the potential to supply a significant portion of North America's growing demand for clean burning natural gas. Devon is the largest holder of exploration licenses and concession acreage in this highly prospective area. In 2002, a Devon well in the Mackenzie Delta encountered 200 to 300 billion cubic feet of potential gas reserves for Devon and its partner.

The challenge ahead is to bring this valuable resource to markets in the south. Various gas transmission pipeline projects are currently under consideration for this stranded resource. While Devon does not expect to participate in the construction of a pipeline, we do expect to transport gas through the finished line. Present projections for the completion of a Mackenzie Valley pipeline are 2007 to 2008, and we are encouraged by the current momentum. Our objective is to have significant gas ready to ship when the pipeline is completed.

You sold your interests in Argentina and Indonesia in 2002. Do you plan to sell your remaining assets outside North America?

Larry Nichols:

Although we chose to divest those international assets, this does not mean that we are disinterested in all international opportunities. We have retained our oil development projects in China and Azerbaijan. In addition, we are actively exploring offshore West Africa and Brazil. Going forward, we will continue to pursue international growth opportunities in areas that meet our investment criteria. In general, we are attracted to countries that offer stable political environments, favorable fiscal regimes, access to strong or growing product markets and projects with the potential to be significant to Devon as a whole.

CORPORATE GOVERNANCE

Devon takes its fiduciary responsibility to its shareholders and investors seriously. In light of recent accounting failures at some high-profile companies, we have initiated a broad-based financial stewardship program to provide even more focus on internal controls and accounting processes. These initiatives include:

- Full compliance with all provisions of the Sarbanes-Oxley Act of 2002. We view this new legislation as an opportunity to assess and strengthen the company's governance policies and procedures.

- Adoption of procedures for auditor independence. KPMG LLP, our independent audit firm, continues to report directly to the Audit Committee of our board of directors.

- Establishment of a corporate disclosure committee to oversee public disclosure and regulatory filings. This committee ensures that Devon provides balanced, timely and accurate disclosures that comply with all legal and regulatory requirements.

- Promotion of a strong ethical climate throughout the organization. Devon's management, with the full support of the board of directors, is committed to maintaining the highest ethical standards of personal and corporate conduct.

These initiatives are consistent with how Devon has operated for decades. We continually review the organization's commitment to these initiatives and reaffirm this commitment to our shareholders.

Devon's Bridgeport, Texas, gas plant processes the liquids-rich gas from our prolific Barnett Shale project.
By owning and managing gas processing operations, Devon can enhance the economic returns of its development projects.

"As a reservoir engineer, I'm involved in oil and gas exploration and development projects. Our asset team evaluates new opportunities in unexplored areas and new reserve potential in existing fields."

SHILPA ABBITT – OKLAHOMA CITY, OKLAHOMA

EXPLORATION AND PRODUCTION PORTFOLIO

Offshore production facilities for Devon's Panyu project in the South China Sea are under construction in Singapore. Installation and first oil production are expected by year-end 2003.

The Anderson and Mitchell acquisitions of late 2001 and early 2002 dramatically expanded the company's property base, making Devon one of North America's largest producers of oil and natural gas. More importantly, by acquiring Anderson and Mitchell's high-quality properties and divesting non-core and low-growth properties, we have significantly improved the profitability and long-term growth potential of our oil and gas asset base.

As we enter 2003, more than 98% of Devon's total oil and natural gas production comes from the western United States, the Gulf of Mexico and western Canada. About two-thirds of this production is natural gas. And while the majority of our 2003 capital budget is focused on low-risk and moderate-risk drilling projects in these core areas, we also have meaningful exposure to longer-term high-impact exploration. This balance provides Devon with a firm foundation for growth well into the future.

THE BARNETT SHALE

Exceeding high expectations

Devon's Barnett Shale project in the Fort Worth Basin of north Texas is among the fastest growing and most exciting onshore natural gas plays in North America. The Barnett Shale is a "tight" reservoir. In tight formations, gas does not flow freely to the wellbore. Stimulation is required to release the gas trapped within the rock. Light sand fracturing (see inset story on page 20) is the stimulation method that has transformed the Barnett Shale into the largest gas field in the state of Texas.

It was the dramatic production growth from the Barnett Shale that initially attracted Devon to Mitchell Energy. But the property has exceeded even our expectations. When we announced our plans to buy Mitchell in August 2001, the Barnett was producing about 350 million equivalent cubic feet of gas per day. Since closing the transaction in January 2002, production has steadily increased. By mid-year 2002, the Barnett was producing 425 million per day and it now produces over 500 million per day. This represents about one-fourth of Devon's total U.S. oil and gas production.

The Barnett Shale holds tremendous additional potential for Devon. We control 545,000 net acres in the area and have developed less than one-fourth of this acreage to date. The undeveloped portion represents thousands of potential undrilled locations. In 2002, Devon drilled 385 Barnett wells, bringing the number of producing wells to about 1,200. We plan to drill another 450 new wells in 2003.

In addition to traditional vertical drilling, we are experimenting with horizontal drilling in the Barnett Shale. Because a horizontal well can drain a broad area, fewer wells may be required to produce the same amount of gas. A typical vertical Barnett Shale well produces about 1 million cubic feet of gas per day when first brought on production. By comparison, early stage horizontal wells are producing three to four times that amount. If these early tests prove to be representative over time, horizontal drilling may further enhance the economic and reserve recovery characteristics of Devon's Barnett Shale assets. Furthermore, horizontal drilling may allow development of areas that could not be developed with vertical wells. We have drilled nine horizontal wells in the Barnett Shale to date and the results are very promising.

In addition to acquiring Mitchell's exploration and production operations, we also acquired its substantial natural gas transportation and processing business. Gas processing allows for the extraction of natural gas liquids such as ethane, propane and butane from the gas stream. Owning processing facilities, especially in liquids-rich areas like the Barnett Shale, gives us greater control over the sale and distribution of our products. This in turn can improve economic returns and ensure that we have adequate gas transmission and processing capacity when needed. A series of expansions at our Bridgeport plant in north Texas has allowed us to keep pace with the rapid production growth of Devon's Barnett gas production.

At a time when North American natural gas production is showing signs of industry-wide decline, the Barnett Shale is bucking that trend. Devon's control of this extraordinary resource represents a unique opportunity for growth.

COALBED METHANE

Building on our experience

Over the last decade, natural gas produced from underground coal deposits, "coalbed methane," has been one of the fastest growing energy sources in North America. This non-conventional natural gas production is characterized by minimal drilling risk, low development costs and low operating costs. It differs from conventional natural gas in that production generally starts out low and increases throughout the early lives of the wells. As the water is pumped out of the coal, the well is "dewatered" and gas production increases.

Devon was a pioneer in coalbed methane production in the mid-1980s in the San Juan Basin of New Mexico. Since then, we have exported our expertise to the Powder River Basin of Wyoming. We also have early-stage pilots in Louisiana and western Canada.

In the Powder River Basin, Devon drilled 140 coalbed methane wells in 2002. We have drilled more than 1,500 wells since we first began the project in 1998. At the end of 2002, Devon's share of production from these wells was about 80 million cubic feet of gas per day. Our current Powder River production is primarily from the shallower Wyodak coals, generally found at depths of less than 1,000 feet. The deeper Big George coals represent additional growth potential. Devon has four Big George pilot projects under way, three of which are now producing commercial quantities of gas. Should they prove successful, we will drill many more Big George wells in the future.

A NATURAL GAS POWERHOUSE

At the wellhead and beyond

Devon produces more than 2 billion cubic feet of natural gas each day or about 3% of all the gas consumed in North America. About one-fourth of that production is from non-conventional sources such as the Barnett Shale and coalbed methane. The balance is produced from conventional producing areas in the United States and Canada.

Devon's conventional production areas include the Permian Basin of southeastern New Mexico and west Texas. In 2002, Devon drilled 120 wells in the Permian, including successful programs in our Anton Irish and Indian Basin fields.

Another important contributor to Devon's conventional gas production is the Washakie field in southwest Wyoming. Devon has achieved steady production growth from this field, currently producing about 80 million cubic feet of gas per day. We drilled 31 Washakie wells in 2002 and plan another 30-well program in 2003. With more than 200,000 net acres and several hundred undrilled locations, we will be actively drilling here for years to come.

Western Canada, where Devon produces from the most prolific gas-prone basins, accounts for more than a third of our natural gas production. Devon is actively drilling in the Deep Basin, northeast British Columbia and Foothills regions. We expect to increase our Deep Basin production over the next few years, from about 90 million cubic feet per day in 2002 to over 140 million per day in 2005. In the Foothills, where we currently produce about 115 million cubic feet per day, we expect to increase production as we tie in recent discoveries in the Grizzly Valley area to a pipeline set for completion by mid-year.

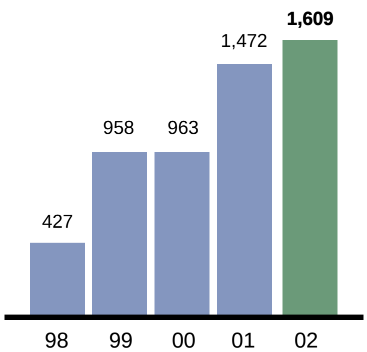
Complementing Devon's producing operations is our network of gas transmission and processing, or midstream, facilities. With ownership in 69 natural gas processing plants in the United States and Canada, Devon has one of the largest midstream operations of any independent. We are also one of the largest independent producers of natural gas liquids.

GULF OF MEXICO SHELF

Better seismic imaging reduces drilling risk

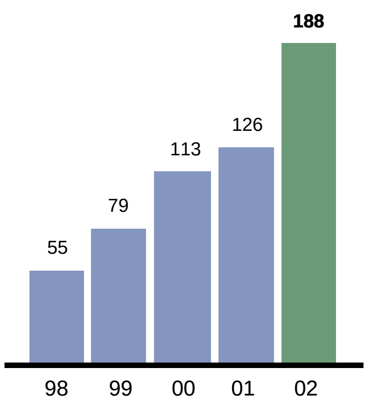
The Gulf of Mexico shelf, defined as water depths of up to 600 feet, accounted for about 10% of Devon's 2002 production. Devon has been successful by leveraging our extensive shelf infrastructure of production facilities and by applying the latest technological tools. An example is Devon's application of four-component, or 4-C, seismic. This innovative technology is proving to be quite effective in reducing drilling risk. In the West Cameron area of the Gulf, Devon has successfully completed four of five exploratory wells drilled on 4-C data. These four wells initially produced a combined 66 million cubic feet of gas per day. Devon plans to drill additional wells based on 4-C seismic during 2003.

RESERVES
(net of royalties) (MMBoe)



The Mitchell acquisition and new drilling increased proved oil and gas reserves to 1.6 billion equivalent barrels...

OIL AND GAS PRODUCTION
(net of royalties) (MMBoe)



...and pushed oil and gas production to record levels in 2002.

The Gulf of Mexico shelf has been drilled for more than 50 years, but relatively few wells have penetrated deeper than 15,000 feet. With the aid of government incentives, a new wave of exploratory drilling is taking place on the "deep shelf," below 15,000 feet. Applying the latest seismic imaging technology is improving the chances for success with deep shelf targets. Devon has identified 10 deep shelf prospects with an estimated 1.4 trillion cubic feet of reserve potential. We expect to drill three deep shelf wells in 2003.

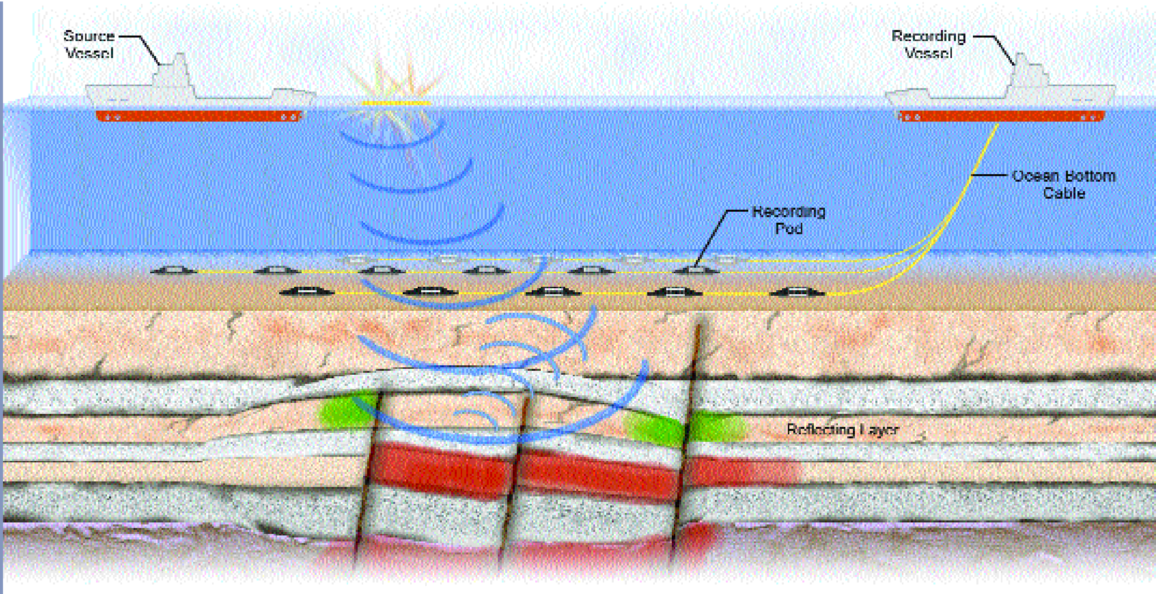
GULF OF MEXICO DEEPWATER

An exciting discovery and a new joint venture

Compared to the shelf, the deepwater Gulf of Mexico is a relatively new frontier. Industry has moved into deeper and deeper water in step with advances in drilling and production technology. In May 2002, Devon's Cascade well discovered what appears to be a very large hydrocarbon-bearing structure in 8,200 feet of water. A delineation well planned for late this year will attempt to further define the size and quality of the reservoir. If those results support further investment, Devon and its partners will evaluate various alternatives for the development of this discovery.

Because costs are much greater in the deep water than on the shelf, we utilize partnerships and joint ventures to limit exposure to any single project. In 2002, Devon joined with ChevronTexaco to participate in four exploratory wells in exchange for a 25% working interest in 71 deepwater blocks. These blocks, combined with Devon's own extensive holdings of deepwater acreage, provide an inventory of high-impact exploratory drilling prospects for several years forward.

FOUR-COMPONENT SEISMIC



Seismic data is used to create visual images of underground rock formations. Geoscientists use these images as a means to help identify oil and gas deposits and to minimize drilling risk. Although seismic technology has been around for decades, only recently have dramatic increases in computing power and new seismic recording techniques made four-component (4-C) seismic possible.

To capture the necessary seismic energy, long cables with recording "pods" spread about 50 yards apart are lowered to the ocean bottom from a recording vessel. The recording pods receive seismic wave signals and transmit them back to the vessel. Each pod is enclosed in a steel cage weighing about 75 pounds. The cages settle into the soft ocean bottom to ensure good contact with the earth. Once the cables are in place, a source vessel creates a series of compressed airbursts. Each airburst produces a seismic or sound wave. The seismic waves are transmitted down into the earth where rock layers reflect the waves back up towards the ocean bottom where they are recorded.

The term "four-component" refers to the orientation of the four separate recording devices housed in each pod. Each device is oriented in a specific direction to record different wave components. The addition of two horizontal geophones inside the pod that measure shear wave signals differentiate 4-C from traditional 2-D or 3-D seismic surveys. Shear waves do not travel through water, so marine surveys must use cables that make contact with the ocean's bottom.

An advantage of 4-C seismic is that it allows geoscientists to "see" beneath shallow gas accumulations just below the ocean bottom and to better define the oil and gas reservoirs below.

This deepwater rig drilled a natural gas discovery for Devon offshore Mississippi in the Gulf of Mexico.

“Devon is exploring for oil and gas in the deep waters of the Gulf of Mexico and West Africa. As the company’s supervisor of deepwater drilling operations, I’m proud to be at the forefront of this effort.”

DANNY HOGAN – HOUSTON, TEXAS

CANADIAN HEAVY OIL
Vast potential

With our 2001 acquisition of Anderson, Devon acquired both conventional cold-flow and thermal heavy oil assets in eastern Alberta. Although more dense than conventional crude oil, cold-flow heavy oil can be produced in its natural state. Thermal heavy oil is so dense that it will not flow unless heated. Heat is typically applied by injecting steam into the formation.

Devon's 2002 cold-flow drilling program at Lloydminster increased our oil production by 5,700 barrels per day. Based on these results, the company is continuing to actively drill at Lloydminster in 2003. Devon's Canadian heavy oil assets also include 300,000 net acres of thermal oil leases. The company plans to invest $35 million in thermal heavy oil projects in 2003.

MACKENZIE DELTA
A future gas pipeline could unlock value

The search for natural gas extends to the northern reaches of our continent, into Canada's Mackenzie Delta and the shallow waters of the Beaufort Sea. With 1.5 million net acres, Devon is the largest exploratory landholder in these areas. Early in 2002, Devon made one of the largest finds in recent years in the Mackenzie Delta. Our Tuk M-18 well, in which we have a 50% working interest, tested significant natural gas flows with gross estimated potential reserves of 200 to 300 billion cubic feet. Recent progress toward construction of a pipeline means Mackenzie Delta gas could be flowing to markets in southern Canada and the United States in the second half of this decade. Devon plans to drill additional exploratory wells in the Mackenzie Delta in the future.

INTERNATIONAL DEVELOPMENTS
Oil from China and drilling in West Africa

Devon first discovered oil in the South China Sea in 1998. A second discovery the following year gave the Panyu project critical mass, with an estimated 80 million barrels of gross reserves. Construction of production facilities is nearing completion, and we expect to see oil flowing in the fourth quarter of 2003. Devon's share is expected to reach 15,000 barrels per day in 2004.

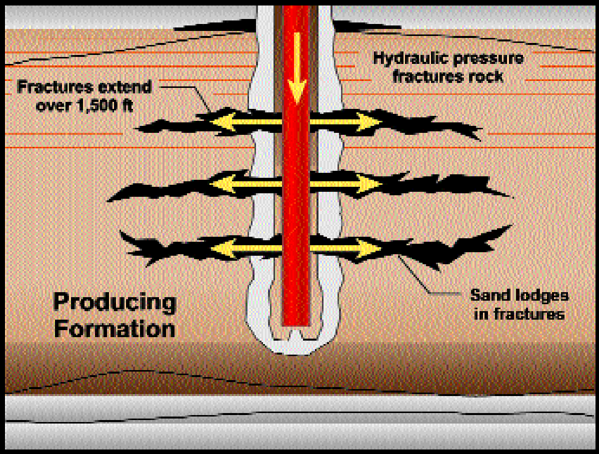
Devon's international exploration program is focused on the South Atlantic Margin, in the waters offshore West Africa and Brazil. We are conducting extensive seismic surveys in both regions where we see similar play concepts. We also plan to drill an exploration well offshore Ghana in 2003.

FRACTURE STIMULATION

Oil and natural gas deposits are found trapped in the pores of underground rock formations. The characteristics of different formations determine how easily oil and gas moves within these pores. Some formations, such as the Barnett Shale, are so "tight" that movement is severely restricted. In such tight formations, it is often necessary to hydraulically fracture the formation to stimulate the movement of oil or gas into a wellbore so it can be brought to the surface.

Fracturing creates small cracks within subsurface rock formations. These cracks, or fractures, serve as pathways to allow the oil and gas to flow more easily. Fluid is pumped into the formation under extreme pressure to fracture the rock. Particles, such as sand, are mixed with the fluid. After the fracturing process is complete, the fluid drains away, leaving behind the particles. The particles, or proppant, prevent the fractures from closing up again. The newly created pathways remain open for the oil or gas to travel toward the wellbore and to the surface.

The "light sand" fracturing method adapted to Devon's Barnett Shale play utilizes water with sand as the proppant. A typical Barnett Shale light sand fracture requires 850,000 gallons of water and 100,000 pounds of sand to create fractures that extend about 1,500 feet from the wellbore.



ENVIRONMENTAL, HEALTH AND SAFETY: TOP PRIORITIES AT DEVON

Devon conducts its operations in accordance with the highest levels of employee, social and environmental responsibility. We believe this commitment is essential to fulfill our business goals and the expectations of our employees and shareholders. During 2002, Devon undertook initiatives to reinforce its commitment to these high standards that included:

- Adopting an enhanced Environmental, Health and Safety (EHS) Philosophy
- Implementing a program of consistent "best practices" throughout the company to ensure that all employees and contractors clearly understand Devon's EHS expectations
- Initiating a comprehensive review and update of all Devon EHS policies
- Adopting an EHS management system

Health and Safety

At Devon, occupational health and safety values will not be compromised. We heighten safety awareness through a comprehensive program reinforced by safety performance and incident investigation training. We also prepare and plan for catastrophic events. In 2002, Devon updated and enhanced its emergency response and business recovery contingency plans.

Environmental Stewardship

We understand the vital relationship between our operations and the environment. To limit and mitigate environmental impact, we seek and adopt technically sound and economically feasible controls wherever we operate.

Devon is routinely recognized by trade organizations and governmental agencies for our commitment to protecting the environment. Recent recognition included:

Photo Courtesy of Gillette News Record

Thom Holmes, operations engineer, surveys land on a Wyoming ranch where the company's coalbed methane development has provided much needed water for the area.

- One of only 13 companies recognized at the highest Platinum level of participation in the Canadian Association of Petroleum Producers' EHS Stewardship Program
- Wyoming Game and Fish Department 2002 Coalbed Methane Natural Resource Stewardship Award. The award recognized Devon's efforts to minimize habitat disturbance on drilling sites and to utilize groundwater released in producing coalbed methane to enhance wildlife habitat.

Commitment

Not only is Devon committed to complying with all applicable environmental, health and safety laws and regulations, we strive to keep our operations compatible with the communities where we do business. We expect to continue to achieve excellence in environmental, health and safety performance through the active participation and support of our management, employees and contractors.

OPERATING STATISTICS BY AREA

		PERMIAN	MID–CONTINENT	ROCKY MOUNTAINS	GULF COAST	GULF OFFSHORE
Producing Wells at Year-End		6,651	5,092	3,045	1,050	663
2002 Production (Net of royalties) (1)						
Oil (MMBbls)		11	2	3	1	7
Gas (Bcf)		61	191	104	42	84
Natural Gas Liquids (MMBbls)		2	9	1	1	1
Total (MMboe) (2)		23	43	21	9	22
Average Prices (1)						
Oil ($/Bbl)	$	22.42	21.73	20.90	22.46	21.70
Gas ($/Mcf)	$	3.29	2.74	2.39	3.30	3.47
Natural Gas Liquids ($/Bbl)	$	14.72	12.54	16.94	14.63	14.06
Year-End Reserves (Net of royalties)						
Oil (MMBbls)		90	9	22	3	23
Gas (Bcf)		283	2,103	835	137	194
Natural Gas Liquids (MMBbls)		13	116	9	4	4
Total (MMboe) (2)		150	475	170	30	60
Year-End Present Value of Reserves (Millions) (3)						
Before Income Tax	$	1,418	3,918	1,100	382	922
After Income Tax	$					
Year-End Leasehold (Net acres in thousands)						
Producing		297	783	287	243	286
Undeveloped		462	1,179	601	91	467
Wells Drilled During 2002 (1)		120	579	196	54	30
2002 Exploration, Development and Facilities Expenditures (Millions) (1,4)	$	79	440	105	80	292
Estimated 2003 Exploration, Development & Facilities Expenditures (Millions) (5)	$	60 - 70	400 - 450	65 - 75	70 - 80	250 - 280

(1) Excludes results from discontinued operations.
(2) Gas converted to oil at the ratio of 6 Mcf:1 Bbl. 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 Securities and Exchange Commission guidelines.
(4) Excludes $108 million spent on marketing and midstream assets.
(5) Excludes $150 to $170 million expected to be spent on marketing and midstream assets.

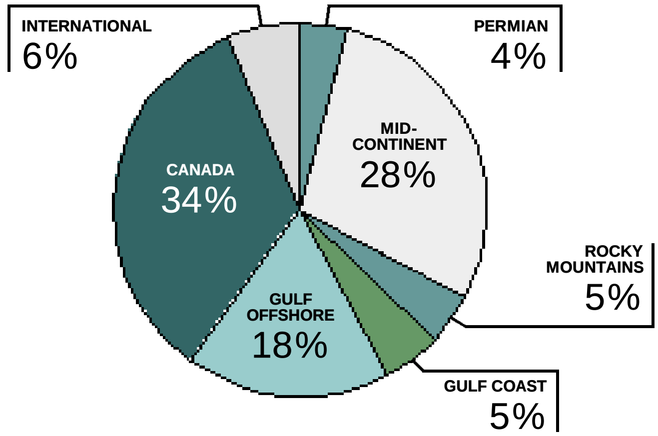
11-YEAR PROPERTY DATA (1)

		1992	1993	1994	1995	1996
Reserves (Net of royalties)						
Oil (MMBbls)		264	257	294	313	351
Gas (Bcf)		645	709	744	860	1,131
Natural Gas Liquids (MMBbls)		7	7	12	16	18
Total (MMBoe) (2)		379	382	430	472	558
10% Present Value (Millions) (3)	$	1,333	1,074	1,485	1,872	3,952
Production (Net of royalties)						
Oil (MMBbls)		25	27	27	28	30
Gas (Bcf)		80	106	101	109	116
Natural Gas Liquids (MMBbls)		1	1	1	1	2
Total (MMBoe) (2)		39	46	45	47	52
Average Prices						
Oil (Per Bbl)	$	14.88	12.94	12.99	15.07	17.49
Gas (Per Mcf)	$	1.63	1.77	1.69	1.44	1.82
Natural Gas Liquids (Per Bbl)	$	12.27	12.51	10.17	10.62	13.78
Oil, Gas and Natural Gas Liquids (Per Boe) (2)	$	13.06	12.04	11.84	12.49	14.90
Production and Operating Expense per Boe (2)	$	5.25	4.91	4.83	4.69	5.24

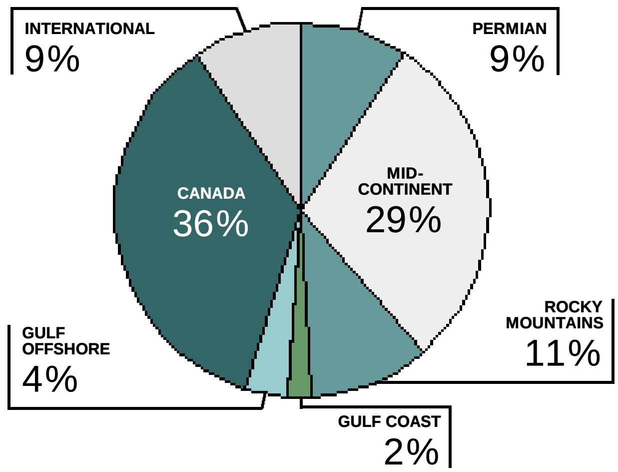
(1) All of the years shown exclude results from Devon's operations in Indonesia, Argentina and Egypt that were discontinued in 2002
Data has been restated to reflect the 1998 merger of Devon and Northstar and the 2000 merger of Devon and Santa Fe Snyder in accordance with the pooling-of-interest method of accounting.
(2) Gas converted to oil at the ratio of 6 Mcf:1Bbl. Natural gas liquids converted to oil at the ratio of 1Bbl:1Bbl.
(3) Before income taxes.

TOTAL U.S.	CANADA	INTERNATIONAL	TOTAL COMPANY
16,501	6,874	20	23,395
24	16	2	42
482	279	-	761
14	5	-	19
118	68	2	188
21.99	21.00	23.70	21.71
2.91	2.62	-	2.80
13.37	15.93	-	14.05
147	149	148	444
3,552	2,284	-	5,836
146	46	-	192
885	576	148	1,609
7,740	6,258	1,309	15,307
5,510	3,890	965	10,365
1,896	2,296	6	4,198
2,800	11,468	7,437	21,705
979	661	45	1,685
996	534	57	1,587
845 - 955	460 - 540	80 - 105	1,385 - 1,600

2003 EXPLORATION, DEVELOPMENT AND FACILITIES BUDGET



PROVED OIL AND GAS RESERVES BY AREA



1997	1998	1999	2000	2001	2002	5-YEAR COMPOUND GROWTH RATE	10-YEAR COMPOUND GROWTH RATE
219	166	439	406	527	444	15%	5%
1,403	1,440	2,785	3,045	5,024	5,836	33%	25%
24	21	55	50	108	192	51%	40%
477	427	958	963	1,472	1,609	28%	16%
2,100	1,375	5,316	17,075	6,687	15,307	49%	28%
29	20	25	37	36	42	8%	5%
180	189	295	417	489	761	33%	25%
3	3	5	7	8	19	46%	40%
62	55	79	113	126	188	25%	17%
17.03	12.28	17.78	24.99	21.41	21.71	5%	4%
2.04	1.78	2.09	3.53	3.84	2.80	7%	6%
12.61	8.08	13.28	20.87	16.99	14.05	2%	1%
14.51	11.09	14.22	22.38	22.19	17.61	4%	3%
4.63	4.29	4.15	4.81	5.29	4.71	-	(1%)

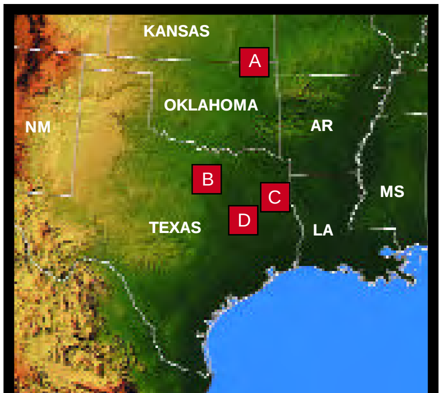
Permian

A Southeast New Mexico

Profile
- 340,000 net acres in southeast New Mexico.
- 65% average working interest.
- Key fields include Indian Basin, Catclaw Draw and Outland/Gaucho.
- Produces oil and gas from multiple formations at 1,500' to 12,500'.
- 47.4 million barrels of oil equivalent reserves at 12/31/02.

2002 Activity
- Drilled and completed 17 gas wells.
- Drilled and completed 10 oil wells.

2003 Plans
- Drill 17 gas wells.
- Drill up to 23 oil wells.
- Evaluate recompletion opportunities.



Mid-Continent

A Cherokee Coalbed Methane

Profile
- 420,000 net acres in southeast Kansas and northeast Oklahoma.
- 100% working interest.
- Initiated in 2001.
- Produces coalbed methane from multiple coal seams at 800' to 2,700'.
- Access to major gas pipelines.
- 22.8 million barrels of oil equivalent reserves at 12/31/02.

2002 Activity
- Drilled 137 coalbed methane wells.
- Completed 206 coalbed methane wells including wells drilled in 2001.
- Constructed 127 miles of gas transmission lines.
- Connected 186 wells to gas sales.
- Installed 167 pumping units for water removal.

2003 Plans
- Complete wells drilled in 2002.
- Drill 143 additional coalbed methane wells.
- Drill 5 water disposal wells.
- Recomplete 33 wells.
- Continue development of gas transmission system.

B Barnett Shale

Profile
- 545,000 net acres in the Fort Worth Basin of north Texas.
- 95% average working interest.
- Obtained in 2002 acquisition.
- Produces gas from the Barnett Shale formation at 6,500' to 8,500'.
- 298.1 million barrels of oil equivalent reserves at 12/31/02.

2002 Activity
- Drilled 380 development wells, including:
  - 32 infill wells on 27-acre spacing.
  - 4 horizontal wells.
- Drilled 5 exploratory wells, including:
  - 3 horizontal wells.
- Refractured 144 wells.
- Completed 2-D and 3-D seismic acquisitions.
- Completed 6th expansion of Bridgeport Plant.
- Constructed 210 miles of gas transmission lines.
- Connected 376 Devon wells to gas sales.

2003 Plans
- Drill approximately 450 development wells.
- Drill 8 exploratory wells.
- Expand horizontal drilling program according to well performance.
- Refracture 64 wells.
- Continue infill-drilling program.

C Carthage/Bethany Area

Profile
- 65% to 85% working interest in 77,000 acres in east Texas.
- Obtained in 1999 merger.
- Produces from the Cotton Valley, Travis Peak and Pettit formations at 5,800' to 9,500'.
- Includes 656 producing wells.
- 58.5 million barrels of oil equivalent reserves at 12/31/02.

2002 Activity
- Drilled and completed 14 wells.
- Performed 33 well recompletion program.

2003 Plans
- Complete 3 wells drilling in late 2002.
- Drill 13 wells.
- Recomplete 50 wells.

D Groesbeck Area

Profile
- 80% average working interest in 140,000 acres in east central Texas.
- Added acreage in 2002 acquisition.
- Produces from the Cotton Valley, Travis Peak and Bossier formations at 6,000' to 12,000'.
- Includes 493 producing wells.
- 31.3 million barrels of oil equivalent reserves at 12/31/02.

2002 Activity
- Drilled and completed 5 wells.
- Recompleted 5 wells.

2003 Plans
- Drill 12 wells.
- Initiate 30 well recompletion program.

Rocky Mountains

A Powder River Coalbed Methane

Profile
- 200,000 net undeveloped and 50,000 net developed acres in northeastern Wyoming.
- 75% average working interest.
- Initial position obtained in 1992 acquisition.
- Produces coalbed methane from the Fort Union Coal formations at 300' to 2,000'.
- 11.5 million barrels of oil equivalent reserves at 12/31/02.

2002 Activity
- Drilled 140 coalbed methane wells (over 120 wells awaiting connection to gas transmission system at year-end).
- Connected 216 wells to gas sales.
- Connected 2 Big George pilots to sales at Pine Tree.

2003 Plans
- Connect remaining wells drilled in 2002 to gas transmission system.
- Drill 113 additional coalbed methane wells.
- Recomplete 22 Wyodak coal wells.
- Connect Big George pilot to sales at Juniper Draw.
- Permit 201 wells on federal lands.

B Jonah/Corona

Profile
- 32% average working interest in 30,000 acres in western Wyoming.
- Obtained in 2000 merger.
- Produces gas from the Lance formation at 7,500' to 10,000'.
- 5.2 million barrels of oil equivalent reserves at 12/31/02.

2002 Activity
- Initiated drilling of 2 infill wells in the Jonah field.
- Initiated drilling of an exploratory well in the Corona Exploration Unit.

2003 Plans
- Complete wells drilled in 2002.
- Evaluate additional drilling opportunities.

C Washakie

Profile
- 76% average working interest in 210,000 acres in southern Wyoming.
- Obtained in 2000 merger.
- Produces gas from multiple formations at 6,800' to 10,300'.
- 67.2 million barrels of oil equivalent reserves at 12/31/02.

2002 Activity
- Drilled and completed 30 gas wells.
- Participated in 45 outside operated wells.
- Recompleted 7 gas wells.

2003 Plans
- Drill 30 gas wells.
- Participate in 50 outside operated wells.
- Recomplete 11 gas wells.

D Bluebell/Altamont

Profile
- 93% working interest in 52,000 acres in northeastern Utah.
- Obtained in 1999 acquisition.
- Produces premium priced yellow crude oil from the Wasatch formation at 8,000’ to 15,000’.
- 10.6 million barrels of oil equivalent reserves at 12/31/02.

2002 Activity
- Completed 3 oil wells drilled in 2001.
- Performed 9 recompletions.

2003 Plans
- Recomplete 4 wells.
- Upgrade salt water disposal system.

E NEBU/32-9 Units

Profile
- 25% working interest in 50,000 acres in the San Juan Basin of northwestern New Mexico.
- Development began in the late 1980s and early 1990s.
- Includes 168 coalbed methane wells, 154 conventional wells, gas and water transmission systems and an automated production control system.
- Produces primarily coalbed methane from the Fruitland Coal formation at 3,000’.
- 25.7 million barrels of oil equivalent reserves at 12/31/02.

2002 Activity
- Recavitated 15 wells.
- Installed 4 pumping units for water removal.
- Drilled and completed 18 conventional gas wells.
- Received regulatory approval for downspacing outside Fruitland Coal fairway.

2003 Plans
- Drill up to 6 infill coalbed methane wells.
- Recavitate 16 wells.
- Drill 30 conventional gas wells.

Gulf Coast

A South Texas

Profile
- Up to 100% working interest in 669,000 acres.
- Obtained in 1999 acquisition & 2000 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’.
- 28.5 million barrels of oil equivalent reserves at 12/31/02.

2002 Activity
- Drilled and completed 43 development wells.
- Drilled and completed 9 exploratory wells.
- Acquired additional acreage and seismic.

2003 Plans
- Drill 40 to 50 development wells.
- Drill 5 to 10 exploratory wells.
- Acquire additional 3-D seismic.

Gulf Offshore – Shelf

A West Cameron Miocene Trend

Profile
- Includes 5 blocks in the West Cameron Miocene Trend area.
- Working interests range from 38% to 100%.
- Located offshore Louisiana in 60’ of water.
- Produces oil and gas from sands at 7,200’ to 14,300’.
- 1.6 million barrels of oil equivalent reserves at 12/31/02.

2002 Activity
- Completed geophysical analysis.

2003 Plans
- Drill exploratory well on West Cameron 181.
- Drill exploratory well on West Cameron 165.
- Drill exploratory well on West Cameron 198.
- Bring in industry partners.
- Pursue shallower development opportunities.

B Main Pass/Viosca Knoll

Profile
- 50% to 52% working interest in 3 blocks in the Main Pass area.
- 47% to 100% working interest in 3 blocks in the Viosca Knoll area.
- Obtained in 2000 merger.
- Located offshore Louisiana in 120’ to 900’ of water.
- Viosca Knoll wells produce through Main Pass facilities.
- Produces oil and gas from multiple sands at 7,900’ to 12,600’.
- 8.5 million barrels of oil equivalent reserves at 12/31/02.

2002 Activity
- Drilled and completed 1 well at Main Pass 259.
- Drilled and completed 1 well at Viosca Knoll 694.
- Completed previous discovery at Main Pass 20.
- Restored production at Viosca Knoll 738.

2003 Plans
- Initiate production at Main Pass 20.
- Drill 1 exploratory well in Main Pass area.
- Drill 1 exploratory well in Viosca Knoll area.
- Evaluate additional prospects.

C South Marsh Island Area

Profile
- Includes 9 fields in the South Marsh Island Area.
- Working interests range from 17% to 100%.
- Obtained in 1999 acquisition.
- Located offshore Louisiana in 200’ of water.
- Produces oil and gas from sands at 3,900’ to 15,000’.
- 4.2 million barrels of oil equivalent reserves at 12/31/02.

2002 Activity
- Drilled and completed 3 wells at South Marsh Island 128.
- Acquired 4-C 3-D seismic data over area.

2003 Plans
- Drill up to 3 wells at South Marsh Island 128.
- Initiate recompletion program at South Marsh Island 23 & 128.
- Evaluate 4-C seismic survey.

D West Cameron 4C Area

Profile
- Includes 17 offshore blocks where Devon is applying 4-C seismic technology.
- Working interests range from 36% to 100%.
- Located offshore Louisiana in 200’ of water.

2002 Activity
- Drilled and completed 1 well at West Cameron 534.
- Drilled and completed 1 well at West Cameron 536.
- Drilled and completed 2 wells at West Cameron 532.

2003 Plans
- Drill 2 wells at West Cameron 575.
- Drill 2 or 3 additional wells.

E High Island 582 (Cyrus)

Profile
- 37% working interest.
- Obtained in 1999 acquisition.
- Located offshore Texas in 440’ of water.
- Produces primarily gas from sands at 4,000’ to 12,000’.
- 5.9 million barrels of oil equivalent reserves at 12/31/02.

2002 Activity
- Completed construction and installation of production facilities.
- Commenced oil and gas production from 4 wells.

2003 Plans
- Produce and monitor.
- Evaluate additional development potential.

F Eugene Island 330 Area

Profile
- Includes 11 fields located in and around Eugene Island 330.
- Working interests range from 23% to 100%.
- Obtained in 1999 acquisition & 2000 merger.
- Located offshore Louisiana in 250’ of water.
- Produces oil and gas from sands at 1,200’ to 9,000’.
- 5.9 million barrels of oil equivalent reserves at 12/31/02.

2002 Activity
- Drilled and completed 3 wells in the Eugene Island 330 field.
- Drilled and completed 2 wells in the Eugene Island 305 field.
- Upgraded water handling capacity at Eugene Island 330.
- Upgraded production facilities at Eugene Island 305.

2003 Plans
- Drill 3 to 6 wells in the area.
- Initiate recompletion program in the Eugene Island 330 field.

Shelf Exploration Prospects

Profile

G Grays

- Galveston 424
- Located offshore Texas in 100' of water.
- Target formation: Mid-Miocene sands at 10,000' to 11,000'.
- 65% working interest.
- Net unrisked reserve potential: 7 million barrels of oil equivalent.

H Puma

- East Cameron 333
- Located offshore Louisiana in 240' of water.
- Target formation: Lower Pliocene sands at 19,000' to 23,000'.
- 50% working interest.
- Net unrisked reserve potential: 6 million barrels of oil equivalent.

2003 Plans

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

Gulf Offshore – Deepwater

A Green Canyon Complex

Profile

- 48% working interest in Green Canyon 112 & 113 (Angus Field).
- 48% working interest in Green Canyon 155 (Manatee Field).
- Obtained in 2000 merger.
- 14.5 million barrels of oil equivalent reserves at 12/31/02.

2002 Activity

- Initiated production from 2 wells at Manatee.

2003 Plans

- Produce and monitor.

B Cascade

Profile

- Walker Ridge 206
- 25% working interest.
- Located offshore Louisiana in 8,200' of water.

2002 Activity

- Drilled discovery well.

2003 Plans

- Finalize follow-up well location with partners.
- Drill follow-up well.

Deepwater Exploration Prospects

Profile

C Tuscany East

- Desoto Canyon 180/224
- Located offshore Louisiana in 6,700' of water.
- Target formation: Middle Miocene sands at 13,500' to 15,000'.
- 25% working interest.
- Net unrisked reserve potential: 30 million barrels of oil equivalent.

D Sturgis

- Second well in ChevronTexaco joint venture.
- Atwater 182
- Located offshore Louisiana in 3,600' of water.
- Target formation: Sub-salt structure in the Atwater Fold Belt Trend at 26,500'.
- 25% working interest.

2003 Plans

- Receive final drilling permit approval.
- Drill exploratory test wells.

Canada

A Mackenzie Delta/Beaufort Sea

Profile

- 46% working interest in 3.2 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.
- Onshore drilling limited to winter only.

2002 Activity

- Drilled the Tuk M-18 discovery well.
- Conducted 50 square mile onshore 3-D seismic survey and 12 square mile 2-D seismic survey.
- Conducted 42 square mile offshore 3-D seismic survey.
- Consolidated offshore licenses into one large license.

2003 Plans

- Drill 2 exploratory wells.
- Evaluate offshore seismic and pursue farm-out opportunities.
- Prepare to secure space on the proposed Mackenzie Valley pipeline.

B Northeast British Columbia

Profile

- 75% average working interest in 2.4 million acres in northwestern Alberta and northeastern British Columbia.
- Key areas include Hamburg, Ladyfern, Wildmint, Tommy Lakes and Wargen.
- Primarily winter-only drilling.
- Produces oil and gas from multiple formations including liquid-rich gas from the Slave Point at 8,000' to 10,000'.
- 78.6 million barrels of oil equivalent reserves at 12/31/02.

2002 Activity

- Drilled and completed 9 Slave Point wells including 5 wells at Ladyfern.
- Obtained pipeline capacity to bring Ladyfer n wells online.
- Drilled and completed 16 Baldonnel wells at Wargen.
- Drilled and completed 37 additional wells in various other areas.

2003 Plans

- Drill 93 total wells, 60% exploratory.
- Drill 7 Slave Point wells at Hamburg and Ladyfern.
- Drill 6 Halfway formation wells at Tommy Lakes.
- Drill 6 Jean Marie formation wells at Peggo.
- Drill 25 wells at Ring Border.

C Northern Plains

Profile

- 75% average working interest in 3.7 million acres in north central Alberta.
- Key areas include Springburn, Hangingstone, Woodenhouse, Goodfish, Kirby, Gift and Dawson.
- Primarily winter-only drilling.
- Produces shallow gas from multiple formations at 1,000' to 2,500'.
- Produces oil and gas from Devonian formations at 6,000' to 9,000'.
- 61.1 million barrels of oil equivalent reserves at 12/31/02.

2002 Activity

- Drilled and completed 112 of 127 wells.

2003 Plans

- Drill 25 shallow wells at Cherpeta.
- Drill 24 shallow wells at Springburn.
- Drill 10 wells at Kirkby.
- Drill 74 additional wells in various other areas.

D Peace River Arch

Profile

- 74% average working interest in 1.5 million acres in western Alberta.
- Key areas include Girouxville, Dunvegan Eaglesham, Pouce Coupe and Valhalla.
- Produces liquids-rich gas and light gravity oil from multiple formations at 4,500' to 8,000'.
- 104.5 million barrels of oil equivalent reserves at 12/31/02.

2002 Activity

- Drilled and completed 71 wells.
- Placed 5,000 barrels per day oil battery on-stream at Girouxville.
- Performed recompletion program at Eaglesham.

2003 Plans

- Drill 71 total wells, 88% exploratory.
- Drill 8 infill wells at Dunvegan.
- Drill 16 wells at Valhalla and Pouce Coupe.

E

Deep Basin

Profile

- 48% average working interest in 1.7 million acres in western Alberta.
- Key areas include Wapiti, Elmworth, Bilbo, Pinto/Leland and Hiding.
- Produces liquids-rich gas from Cretaceous and Devonian formations at 3,000’ to 13,500’.
- 68.0 million barrels of oil equivalent reserves at 12/31/02.

2002 Activity

- Drilled and completed 56 of 60 wells.
- Increased gas production 27%.
- Placed production facility on stream at Elmworth.

2003 Plans

- Drill 98 total wells, 50% exploratory.
- Drill 24 wells at Pinto/Leland.
- Drill 25 wells at Bilbo.
- Expand production facilities at Elmworth and Leland.

F

Foothills

Profile

- 53% working interest in 1.2 million acres in western Alberta and eastern British Columbia.
- Key exploratory areas include Grizzly Valley in eastern British Columbia, Narraway, Cabin Creek and Findley in west central Alberta and Moose in southern Alberta.
- High-impact, long-lived reserves.
- Produces gas from multiple formations at 4,000’ to 15,000’.
- 79.1 million barrels of oil equivalent reserves at 12/31/02.

2002 Activity

- Drilled and completed 27 of 30 gas wells.
- Drilled 2 successful exploratory wells in the Grizzly Valley area.
- Commenced operations of 135 million cubic feet of gas per day sweet gas processing plant at Narraway.
- Initiated production from the Grizzly Valley area at 10 million cubic feet of gas per day, previously limited by facilities.

2003 Plans

- Drill 34 total wells, 75% exploratory.
- Drill up to 8 wells at Grizzly Valley.
- Increase production from Grizzly Valley area to 35 million cubic feet of gas per day as facilities are expanded.
- Drill at least 20 wells at Findley, Narraway and Bighorn.
- Evaluate gas potential at Moose.

G

Heavy Oil

Profile

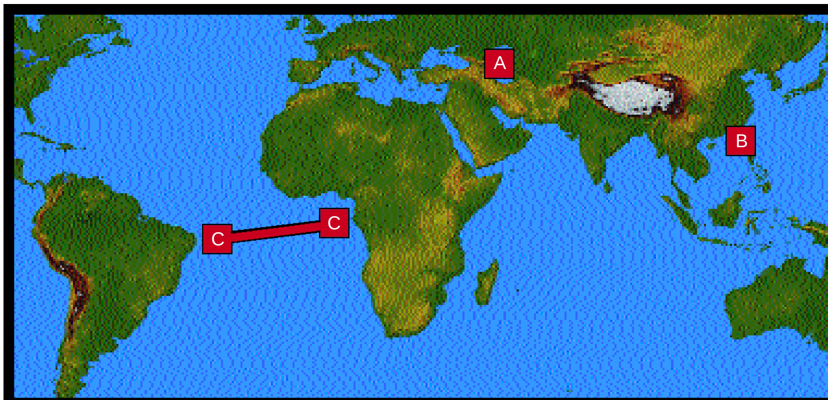
- 95% average working interest in 1.8 million acres in northeastern Alberta.
- Key areas include Manatokan, Lloydminster, Dover, Jackfish and Surmont.
- Acreage contains prospects suitable for both conventional and thermal recovery.
- 64.2 million barrels of oil equivalent reserves at 12/31/02.

2002 Activity

- Drilled and completed 215 Lloydminster conventional heavy oil wells.
- Drilled 88 delineation wells at Trout, Jackfish and Surmont.

2003 Plans

- Drill 134 Lloydminster conventional heavy oil wells.
- Drill 80 delineation wells at Jackfish and 2 horizontal well pairs at Dover.
- Investigate new solvent recovery technologies in thermal areas.
- Participate in phase 1 development of Surmont project.



International

A

Azerbaijan

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 acquisition.
- Oil is exported by pipeline to the west and north.
- Anticipate significant production and revenue to Devon commencing in 2009.
- 125.1 million barrels of oil equivalent reserves at 12/31/02.

2002 Activity

- Drilled 2 extended reach wells from the Chirag platform.
- Drilled 6 of 12 pre-drill wells for the Azeri platform.
- Acquired 4-C 3-D seismic survey over the Azeri and Chirag portions of the field.
- Began construction on phase 1 field development.
- Sanctioned phase 2 field development.
- Received approval for and commenced construction of the main export pipeline from Baku to Ceyhan, Turkey.

2003 Plans

- Drill 1 extended reach well from the Chirag platform.
- Drill remaining 6 pre-drill wells for the Azeri platform.
- Expand fluid handling facilities.
- Commence pre-drill operations on the phase 2 Azeri platform.
- Continue construction of main export pipeline.

B

China

Profile

- 1.9 million net acres in 4 licensed blocks in the Pearl River Mouth Basin offshore China.
- Located in 300’ of water.
- Initial position obtained in 2000 merger.
- Includes 1998 and 1999 Panyu oil discoveries.
- 17.8 million barrels of oil equivalent reserves at 12/31/02.

2002 Activity

- Continued construction of 2 separate Panyu drilling and production facilities.
- Continued construction of 1 million barrel floating production, storage and offloading vessel (FPSO).

2003 Plans

- Finish construction and installation of Panyu facilities.
- Commission FPSO.
- Drill 15 development Panyu wells with first production scheduled for late 2003.
- Drill 1 exploratory well on block 16/02.

C

South Atlantic Margin

Profile

- 2.7 million net acres in 4 licensed blocks offshore West Africa:
  Keta block offshore Ghana; 56% interest.
  Agali block offshore Gabon; 50% interest.
  Kowe block offshore Gabon; 19% interest.
  Marine IX block offshore Congo; 47% interest.
- 624,000 net acres in 2 licensed blocks offshore Brazil:
  BM-BAR-3 block; 100% interest.
  BM-C-8 block; 45% interest.
- Obtained initial positions in 1999 acquisition and 2000 merger.
- Interest in 7 producing oil wells on the Kowe block.
- 4.9 million barrels of oil equivalent reserves at 12/31/02.

2002 Activity

- Installed 27-mile oil export pipeline to replace floating storage and offloading vessel on the Kowe block.
- Installed sour crude facilities to initiate Azile formation development on the Kowe Block.
- Interpreted 3-D seismic data on the Keta and Agali blocks.
- Awarded deepwater block BM-BAR-3.

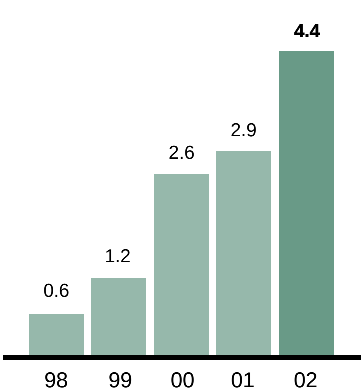
2003 Plans

- Drill development well on the Kowe block.
- Acquire 3-D seismic survey on Kowe block.
- Drill deepwater exploratory well on the Keta block.

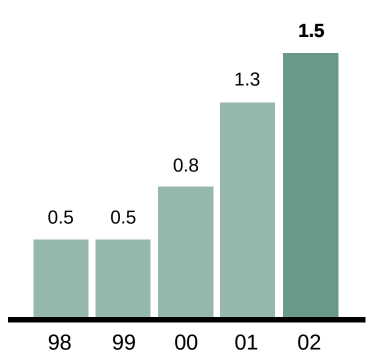
Featured employees clockwise, from upper left: Michel Scott, Calgary; Marvinette Ponder, Brandon McGinley, Jaren Howard and Jennifer Day, Oklahoma City; and Kenneth Walker, Bridgeport.

FINANCIAL STATEMENTS AND MANAGEMENT'S DISCUSSION AND ANALYSIS

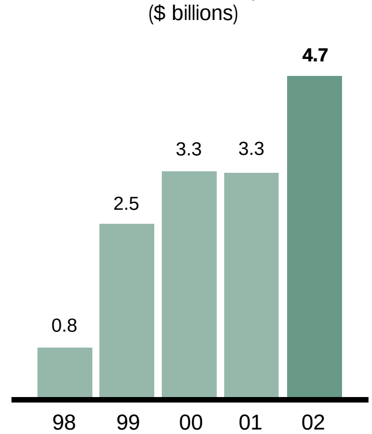
TOTAL REVENUES
($ billions)



CAPITAL EXPENDITURES FOR EXPLORATION AND DEVELOPMENT
($ billions)



STOCKHOLDERS' EQUITY
($ billions)



SELECTED 11-YEAR FINANCIAL DATA (1)

		1992	1993	1994	1995
OPERATING RESULTS (IN MILLIONS, EXCEPT PER SHARE DATA)					
Revenues (Net of royalties):					
Oil sales	$	367	355	351	419
Gas sales	$	131	189	171	157
Natural gas liquids sales	$	8	13	13	15
Marketing & midstream revenues	$	-	-	-	-
Other income	$	11	31	14	35
Total revenues	$	517	588	549	626
Production and operating expenses	$	203	227	218	222
Marketing & midstream operating costs and expenses	$	-	-	-	-
Depreciation, depletion and amortization of property and equipment	$	147	170	149	160
Amortization of goodwill (2)	$	-	-	-	-
General and administrative expenses	$	43	51	45	43
Expenses related to mergers	$	-	11	7	-
Interest expense (3)	$	51	42	29	39
Foreign exchange effect	$	-	-	-	-
Change in fair value of financial instruments	$	-	-	-	-
Reduction of carrying value of oil and gas properties	$	-	180	22	97
Impairment of ChevronTexaco Corporation common stock	$	-	-	-	-
Income tax expense (benefit)	$	19	(68)	25	19
Total expenses	$	463	613	495	580
Net earnings (loss) before minority interest, cumulative effect of change in accounting principle and discontinued operations (4)	$	54	(25)	54	46
Net earnings (loss)	$	11	(55)	54	55
Preferred stock dividends	$	6	7	11	15
Net earnings (loss) to common shareholders	$	5	(62)	43	40
Net earnings (loss) per common share:					
Basic	$	0.14	(1.27)	0.84	0.76
Diluted	$	0.13	(1.27)	0.84	0.76
Weighted average shares outstanding:					
Basic		39	49	51	52
Diluted		42	49	54	53
BALANCE SHEET DATA (IN MILLIONS)					
Total assets	$	1,464	1,336	1,475	1,639
Debentures exchangeable into shares of ChevronTexaco Corporation common stock (5)	$	-	-	-	-
Other long-term debt (6)	$	571	508	457	565
Deferred income taxes	$	52	-	30	48
Stockholders' equity	$	503	472	688	739
Common shares outstanding		48	49	52	52

(1) All of the years shown exclude results from Devon's operations in Indonesia, Argentina and Egypt that were discontinued in 2002.
(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) and $49 million in 1993 and 2001, respectively and the results of discontinued operations of ($43), ($29), $0, $9, $15, $13, ($35), $39, $69, $31 and $45 million in 1992 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.

1996	1997	1998	1999	2000	2001	2002	5-YEAR GROWTH RATE	10-YEAR GROWTH RATE
529	497	236	436	906	784	909	13%	10%
211	367	335	616	1,474	1,878	2,133	42%	32%
29	36	25	68	154	131	275	50%	42%
-	10	8	20	53	71	999	151%	NM
36	42	22	10	40	69	34	(4%)	12%
805	952	626	1,150	2,627	2,933	4,350	36%	24%
271	288	231	328	544	666	886	25%	16%
-	4	3	10	28	47	808	189%	NM
175	268	212	379	662	831	1,211	35%	24%
-	-	-	16	41	34	-	NM	NM
57	56	48	83	96	114	219	31%	18%
-	-	13	17	60	1	-	NM	NM
59	51	53	122	155	220	533	60%	26%
-	6	16	(13)	3	11	(1)	(170%)	NM
-	-	-	-	-	2	(28)	NM	NM
-	633	354	476	-	979	651	1%	NM
-	-	-	-	-	-	205	NM	NM
106	(128)	(103)	(75)	377	5	(193)	9%	NM
668	1,178	827	1,343	1,966	2,910	4,291	30%	25%
137	(226)	(201)	(193)	661	23	59	NM	1%
151	(218)	(236)	(154)	730	103	104	NM	25%
47	12	-	4	10	10	10	(4%)	5%
104	(230)	(236)	(158)	720	93	94	NM	34%
1.97	(3.35)	(3.32)	(1.68)	5.66	0.73	0.61	NM	16%
1.92	(3.35)	(3.32)	(1.68)	5.50	0.72	0.61	NM	17%
53	69	71	94	127	128	155	18%	15%
56	75	77	99	132	130	156	16%	14%
2,242	1,965	1,931	6,096	6,860	13,184	16,225	53%	27%
-	-	-	760	760	649	662	NM	NM
511	576	885	1,656	1,289	5,940	6,900	64%	28%
136	50	15	313	634	2,149	2,627	121%	48%
1,160	1,006	750	2,521	3,277	3,259	4,653	36%	25%
63	71	71	126	129	126	157	17%	13%

OVERVIEW

On January 24, 2002, we completed our acquisition of Mitchell Energy & Development Corp. ("Mitchell"). Under the terms of this agreement, 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 billion senior unsecured term loan credit facility. The Mitchell merger added approximately 404 million Boe to our proved reserves.

Following the Mitchell announcement in August 2001, we announced on September 4, 2001, that we had entered into an agreement to acquire Anderson Exploration Ltd. ("Anderson") for approximately $3.5 billion in cash. This acquisition closed on October 15, 2001, and therefore had an impact on Devon's results for the last two and one-half months of 2001. The Anderson acquisition added approximately 534 million Boe to our proved reserves.

To fund the cash portions of these two acquisitions, as well as to pay related transaction costs and retire certain long-term debt assumed from Mitchell and Anderson, Devon entered into long-term debt agreements in October 2001 that totaled $6 billion. Half of this total consisted of $3 billion of notes and debentures issued on October 3, 2001. Of this total, $1.25 billion bears interest at 7.875% and matures in September 2031. The remaining $1.75 billion bears interest at 6.875% and matures in September 2011.

The remaining $3 billion of the $6 billion of long-term debt is in the form of a credit facility that bears interest at floating rates. As of December 31, 2002, $1.9 billion of the original $3 billion balance had been retired. The primary sources of the repayments were the issuance of $1 billion of debt securities, of which $0.8 billion was used to pay down debt, and $1.4 billion from the sale of certain oil and gas properties, of which $1.1 billion was used to pay down debt. As of December 31, 2002, the balance outstanding under the term loan credit facility was $1.1 billion at an average rate of 2.5%. Principal payments due on this debt are $0.3 billion in April 2006 and $0.8 billion in October 2006.

The Mitchell and Anderson acquisitions followed another significant acquisition. In August 2000, Devon closed its merger with Santa Fe Snyder Corporation. This transaction added approximately 386 million Boe to Devon's proved reserves.

In addition to these mergers and acquisitions, exploration and development efforts have also been significant contributors to our growth. In 2002, we spent $1.5 billion for exploration, drilling and development. These costs included drilling 1,685 wells, of which 1,599 were completed as producers. In 2000 and 2001, Devon spent an aggregate of $2 billion in its exploration, drilling and development efforts. These costs included drilling 2,873 wells, of which 2,705 were completed as producers.

The following statistics illustrate the effects that Devon's mergers and acquisitions and our drilling and development activities have had on operations during the last three years. This data compares Devon's 2002 results to those of 2000 for Devon combined with Santa Fe Snyder. It was acquired in a merger accounted for under the pooling-of-interests method. Such comparison yields the following fluctuations:

- **Proved reserves increased 651 million Boe, or 68%.**
- **Combined oil, gas and NGL production increased 75 million Boe, or 66%.**
- **Total revenues increased $1.7 billion, or 67%.**
- **Net cash provided by operating activities increased $165 million, or 10%.**

During 2002, we marked our 14th anniversary as a public company. While Devon has consistently increased production over this 14-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 our 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 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. Our future growth, if any, will depend on our ability to continue to add reserves in excess of production.

Oil, gas and NGL prices are influenced by many factors outside of our control. As a result, Devon's management has focused its efforts on increasing oil and gas reserves and production and controlling expenses. Over our 14-year history as a public company, Devon has been able to reduce controllable operating costs per unit of production. Devon's future earnings and cash flows are dependent on our ability to continue to contain operating costs at levels that allow for profitable production.

RESULTS OF OPERATIONS

Revenues Changes in oil, gas and NGL production, prices and revenues from 2000 to 2002 are shown in the following tables. (Unless otherwise stated, all dollar amounts in this report are expressed in U.S. dollars.)

	TOTAL YEAR ENDED DECEMBER 31,					
		2002	2002 vs 2001	2001	2001 vs 2000	2000
PRODUCTION						
Oil (MMBbls)		42	+17%	36	-3%	37
Gas (Bcf)		761	+56%	489	+17%	417
NGLs (MMBbls)		19	+138%	8	+14%	7
Oil, gas and NGLs (MMBoe)		188	+50%	126	+12%	113
AVERAGE PRICES						
Oil (per Bbl)	$	21.71	+1%	21.41	-14%	24.99
Gas (per Mcf)	$	2.80	-27%	3.84	+9%	3.53
NGLs (per Bbl)	$	14.05	-17%	16.99	-19%	20.87
Oil, gas and NGLs (per Boe)	$	17.61	-21%	22.19	-1%	22.38
REVENUES ($ in millions)						
Oil	$	909	+16%	784	-13%	906
Gas	$	2,133	+14%	1,878	+27%	1,474
NGLs	$	275	+110%	131	-15%	154
Oil, gas and NGLs	$	3,317	+19%	2,793	+10%	2,534

	DOMESTIC YEAR ENDED DECEMBER 31,					
		2002	2002 vs2001	2001	2001 vs2000	2000
PRODUCTION						
Oil (MMBbls)		24	-8%	26	-10%	29
Gas (Bcf)		482	+28%	376	+6%	355
NGLs (MMBbls)		14	+133%	6	+0%	6
Oil, gas and NGLs (MMBoe)		118	+24%	95	+1%	94
AVERAGE PRICES						
Oil (per Bbl)	$	21.99	-2%	22.36	-12%	25.45
Gas (per Mcf)	$	2.91	-30%	4.17	+14%	3.67
NGLs (per Bbl)	$	13.37	-22%	17.15	-16%	20.30
Oil, gas and NGLs (per Boe)	$	17.87	-25%	23.80	+4%	22.95
REVENUES ($ in millions)						
Oil	$	524	-11%	586	-19%	727
Gas	$	1,403	-11%	1,571	+20%	1,305
NGLs	$	192	+86%	103	-24%	136
Oil, gas and NGLs	$	2,119	-6%	2,260	+4%	2,168

	CANADA YEAR ENDED DECEMBER 31,				
	2002	2002 vs 2001	2001	2001 vs2000	2000
PRODUCTION					
Oil (MMBbls)	16	+100%	8	+60%	5
Gas (Bcf)	279	+147%	113	+82%	62
NGLs (MMBbls)	5	+150%	2	+100%	1
Oil, gas and NGLs (MMBoe)	68	+134%	29	+81%	16
AVERAGE PRICES					
Oil (per Bbl)	$ 21.00	+18%	17.84	-27%	24.46
Gas (per Mcf)	$ 2.62	-4%	2.73	+1%	2.71
NGLs (per Bbl)	$ 15.93	-3%	16.43	-38%	26.51
Oil, gas and NGLs (per Boe)	$ 16.96	+1%	16.80	-12%	19.18
REVENUES ($ in millions)					
Oil	$ 331	+127%	146	+26%	116
Gas	$ 730	+138%	307	+82%	169
NGLs	$ 83	+196%	28	+56%	18
Oil, gas and NGLs	$ 1,144	+138%	481	+59%	303

	INTERNATIONAL YEAR ENDED DECEMBER 31,				
	2002	2002 vs2001	2001	2001 vs 2000	2000
PRODUCTION					
Oil (MMBbls)	2	+0%	2	-33%	3
Gas (Bcf)	--	NM	--	NM	--
NGLs (MMBbls)	--	NM	--	NM	--
Oil, gas and NGLs (MMBoe)	2	+0%	2	-33%	3
AVERAGE PRICES					
Oil (per Bbl)	$ 23.70	+1%	23.42	+9%	21.44
Gas (per Mcf)	$ --	NM	--	NM	--
NGLs (per Bbl)	$ --	NM	--	NM	--
Oil, gas and NGLs (per Boe)	$ 23.70	+1%	23.42	+9%	21.44
REVENUES ($ in millions)					
Oil	$ 54	+4%	52	-17%	63
Gas	$ --	NM	--	NM	--
NGLs	$ --	NM	--	NM	--
Oil, gas and NGLs	$ 54	+4%	52	-17%	63

The average prices shown in the preceding tables include the effect of Devon's oil and gas commodity 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		
	2002	2001	2000	2002	2001	2000
Oil (per Bbl)	$ 21.71	21.41	24.99	$ 22.63	21.79	26.00
Gas (per Mcf)	$ 2.80	3.84	3.53	$ 2.70	3.89	3.61
NGLs (per Bbl)	$ 14.05	16.99	20.87	$ 14.05	16.99	20.87
Oil, gas and NGLs (per Boe)	$ 17.61	22.19	22.38	$ 17.36	22.48	23.01

Oil Revenues 2002 vs. 2001 Oil revenues increased $125 million in 2002. An increase in production of 6 million barrels caused oil revenues to increase by $112 million. The Anderson and Mitchell acquisitions accounted for 11 million barrels of increased production. This was partially offset by the effect of divestitures, which reduced 2002 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.

2001 vs. 2000 Oil revenues decreased $122 million in 2001. A $3.58 per barrel decrease in 2001's average price caused revenues to drop by $114 million. A decrease in production of one million barrels caused oil revenues to decrease by an additional $8 million. The October 2001 Anderson merger accounted for three million barrels of 2001 production. However, oil production from Devon's other properties declined four million barrels. This reduction was primarily the result of domestic and international properties that were sold prior to 2001 but whose production was included in 2000 prior to the sales.

Gas Revenues 2002 vs. 2001 Gas revenues increased $255 million in 2002. An increase in production of 272 Bcf caused gas revenues to increase by $1 billion. The Anderson and Mitchell acquisitions accounted for 323 Bcf of increased production. This was partially offset by the effect of divestitures, which reduced 2002 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.

2001 vs. 2000 Gas revenues increased $404 million in 2001. Of this total increase, $253 million was due to a 72 Bcf increase in production in 2001. The October 2001 Anderson merger accounted for 51 Bcf of the increase. Production from our domestic properties increased 21 Bcf, due primarily to drilling and development in our coalbed methane properties as well as the acquisition of certain properties in the second quarter of 2001. A $0.31 per Mcf increase in the average gas price in 2001 accounted for the remaining $151 million of increased gas revenues.

NGL Revenues 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 and Mitchell acquisitions 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.

2001 vs. 2000 NGL revenues decreased $23 million in 2001. A decrease in 2001's average price of $3.88 per barrel caused NGL revenues to decrease $30 million. This was partially offset by a $7 million increase related to a production increase of one million barrels. The October 2001 Anderson merger accounted for all of the increase.

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

2001 vs. 2000 Marketing and midstream revenues increased $18 million in 2001. This increase was primarily the result of capacity additions to Devon's Wyoming gas pipeline systems.

Operating Costs and Expenses The details of the changes in operating costs and expenses between 2000 and 2002 are shown in the table below.

	YEAR ENDED DECEMBER 31,				
	2002	2002 vs2001	2001	2001 vs 2000	2000
Absolute (in millions):					
Production and operating expenses:					
Lease operating expenses	$ 621	+33%	467	+20%	388
Transportation costs	154	+86%	83	+57%	53
Production taxes	111	-4%	116	+13%	103
Depreciation, depletion and amortization of oil and gas properties	1,106	+39%	793	+25%	632
Amortization of goodwill	--	-100%	34	-17%	41
Subtotal	1,992	+33%	1,493	+23%	1,217
Marketing and midstream operating costs and expenses	808	+1,619%	47	+68%	28
Depreciation and amortization of non-oil and gas properties	105	+176%	38	+27%	30
General and administrative expenses	219	+92%	114	+19%	96
Expenses related to mergers	--	-100%	1	-98%	60
Reduction of carrying value of oil and gas properties	651	-34%	979	NM	--
Total	$ 3,775	+41%	2,672	+87%	1,431
Operating costs and expenses per Boe:					
Production and operating expenses:					
Lease operating expenses	$ 3.30	-11%	3.71	+8%	3.43
Transportation costs	0.82	+24%	0.66	+40%	0.47
Production taxes	0.59	-36%	0.92	+1%	0.91
Depreciation, depletion and amortization of oil and gas properties	5.88	-7%	6.30	+13%	5.58
Amortization of goodwill	--	-100%	0.27	-27%	0.37
Subtotal	10.59	-11%	11.86	+10%	10.76
Marketing and midstream operating costs and expenses (1)	4.29	+1,059%	0.37	+48%	0.25
Depreciation and amortization of non-oil and gas properties (1)	0.55	+83%	0.30	+11%	0.27
General and administrative expenses (1)	1.16	+27%	0.91	+7%	0.85
Expenses related to mergers (1)	--	-100%	0.01	-98%	0.53
Reduction of carrying value of oil and gas properties (1)	3.45	-56%	7.78	NM	--
Total	$ 20.04	-6%	21.23	+68%	12.66

(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.
NM – Not meaningful.

Oil, Gas and NGL Production and Operating Expenses The details of the changes in production and operating expenses related to oil, gas and NGL producing activities between 2000 and 2002 are shown in the table below.

	YEAR ENDED DECEMBER 31,				
	2002	2002 vs2001	2001	2001 vs2000	2000
Expenses ($ in millions):					
Lease operating expenses	$ 621	+33%	467	+20%	388
Transportation costs	154	+86%	83	+57%	53
Production taxes	111	-4%	116	+13%	103
Total production and operating expenses	$ 886	+33%	666	+22%	544
Expenses per Boe:					
Lease operating expenses	$ 3.30	-11%	3.71	+8%	3.43
Transportation costs	0.82	+24%	0.66	+40%	0.47
Production taxes	0.59	-36%	0.92	+1%	0.91
Total production and operating expenses	$ 4.71	-11%	5.29	+10%	4.81

2002 vs. 2001 Lease operating expenses increased $154 million in 2002. The Anderson and Mitchell acquisitions 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 and Mitchell acquisitions and the divestiture of some of Devon's higher cost properties.

Transportation costs represent those costs paid directly to third-party providers to transport oil, gas and NGL production sold downstream from the wellhead. Transportation costs increased $71 million in 2002 primarily due to an increase in gas production from the Anderson and Mitchell acquisitions.

The majority of Devon's production taxes are assessed on its onshore domestic properties. In the U.S., most of the 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 a 4% decrease in production taxes.

2001 vs. 2000 Recurring lease operating expenses increased $79 million in 2001.The Anderson acquisition accounted for $47 million of the increase in expenses. The remaining increase in recurring costs was primarily caused by higher third-party service, fuel and electricity costs.

Transportation costs increased $30 million in 2001. Of this increase, $12 million related to the Anderson acquisition. The remainder of the increase was primarily due to an increase in gas production from our domestic drilling and development activities.

As previously stated, most of the U.S. production taxes are based on a fixed percentage of revenues. Therefore, the 4% increase in domestic oil, gas and NGL revenues was the primary cause of an 11% increase in domestic production taxes. Production taxes did not increase proportionately to the increase in revenues. This was primarily due to the fact that most of the increase in domestic revenues occurred in the Rocky Mountain and Permian Basin areas, which have higher production tax rates than the other domestic areas.

Depreciation, Depletion and Amortization ("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 depletable base. The depletable base is the net capitalized investment in those reserves, including estimated future development and dismantlement and abandonment costs. 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.

2002 vs. 2001 Oil and gas property related DD&A increased $313 million in 2002. A 50% increase in 2002's oil, gas and NGL 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.

Non-oil and gas property DD&A increased $67 million in 2002 compared to 2001. Depreciation of the marketing and midstream assets acquired in the January 2002 Mitchell acquisition accounted for substantially all of the increase.

2001 vs. 2000 Oil and gas property related DD&A increased $161 million in 2001. Of this total increase, $70 million was due to the 12% increase in oil, gas and NGL production in 2001. The remaining $91 million increase was due to an increase in the consolidated DD&A rate. This rate increased from $5.58 per Boe in 2000 to $6.30 per Boe in 2001.

Non-oil and gas property DD&A increased $8 million in 2001 compared to 2000. Depreciation of Devon's Wyoming gas pipeline systems accounted for the 2001 increase.

Amortization of Goodwill Effective January 1, 2002, Devon adopted the remaining provisions of Statement of Financial Accounting Standards No. 142, Goodwill and Other Intangible Assets (SFAS No. 142). Under SFAS No. 142, goodwill and intangible assets with indefinite useful lives are no longer amortized as they were prior to 2002, but are instead tested for impairment at least annually. Prior to the adoption of SFAS No. 142, Devon's goodwill amortization was $34 million and $41 million in 2001 and 2000, respectively.

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

2001 vs. 2000 Marketing and midstream operating costs and expenses increased $19 million in 2001. This increase was primarily the result of capacity additions to Devon's Wyoming gas pipeline systems.

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 which we operate. 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,					
		2002	2002 vs2001	2001	2001 vs 2000	2000
				(IN MILLIONS)		
Gross G&A	$	387	+56%	248	+19%	209
Capitalized G&A		(97)	+26%	(77)	+24%	(62)
Reimbursed G&A		(71)	+25%	(57)	+12%	(51)
Net G&A	$	219	+92%	114	+19%	96

2002 vs. 2001 Gross G&A increased $139 million primarily due to additional costs incurred as a result of the Anderson and Mitchell acquisitions. Also included in 2002's gross G&A was $13 million related to the abandonment of certain office space assumed in the Santa Fe Snyder merger. G&A was reduced $20 million due to an increase in the amount capitalized as part of oil and gas properties. G&A was also reduced $14 million by an increase in the amount of reimbursements on properties we operate. Changes in both the capitalized and reimbursed amounts were primarily related to the Anderson and Mitchell acquisitions.

2001 vs. 2000 Gross G&A increased $39 million primarily due to additional costs incurred as a result of the Anderson acquisition and other personnel related costs. G&A was reduced $15 million due to an increase in the amount capitalized. The increase in capitalized G&A was primarily related to additional personnel related costs and increased acquisition, exploration and development activities. G&A was also reduced $6 million by an increase in the amount of reimbursements on operated properties. The increase in reimbursed G&A was primarily related to an increase in the number of operated properties.

Expenses Related to Mergers Approximately $1 million of expenses were incurred in 2001 in connection with the Anderson acquisition. These costs related to Devon employees who were terminated as part of the Anderson acquisition.

Approximately $60 million of expenses were incurred in 2000 in connection with the Santa Fe Snyder merger. These expenses were primarily severance and other benefit costs, investment banking fees, other professional expenses, costs associated with duplicate facilities and various transaction related costs. The pooling-of-interests method of accounting for business combinations required such costs be expensed as opposed to capitalized as costs of the transaction.

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, 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 imposed separately by country. In calculating future net revenues, current prices and costs are generally held constant indefinitely. We do not include the effect of hedges 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.

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 2002 and 2001, we reduced the carrying value of our oil and gas properties by $651 million and $883 million, respectively, due to full cost ceiling limitations. The after-tax effect of these reductions in 2002 and 2001 was $371 million and $533 million, respectively. The following table summarizes these reductions by country.

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

The 2002 Canadian reduction was primarily the result of lower prices. Under the purchase method of accounting for business combinations, acquired oil and gas properties are recorded at fair value as of the date of purchase. We estimate 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 is not necessarily indicative of the fair value of the reserves. 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 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, our Canadian costs to be recovered exceeded their 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, we elected to abandon operations in Thailand, Malaysia, Qatar and certain properties in Brazil. After meeting the drilling and capital commitments on these properties, we determined 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.

Effective January 1, 2002, Devon was required to adopt the provisions of SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets. The provisions of SFAS No. 144 only apply prospectively. As a result, these impairment charges have not been reclassified as part of the Discontinued Operations on the consolidated statements of operations.

Other Income (Expenses) The details of the changes in other income (expenses) between 2000 and 2002 are shown in the table below.

	2002	2001	2000
		(IN MILLIONS)	
Other income (expenses):			
Interest expense:			
Interest based on debt outstanding	$ (499)	(200)	(157)
(Accretion) amortization of debt (discount) premium, net	(13)	(10)	4
Facility and agency fees	(2)	(1)	(3)
Amortization of capitalized loan costs	(8)	(3)	(2)
Capitalized interest	4	3	3
Early retirement premiums	(8)	(7)	--
Other	(7)	(2)	--
Total interest expense	(533)	(220)	(155)
Effects of changes in foreign currency exchange rates	1	(11)	(3)
Change in fair value of financial instruments	28	(2)	--
Impairment of ChevronTexaco Corporation common stock	(205)	--	--
Other income	34	69	40
Total	$ (675)	(164)	(118)

Interest Expense 2002 vs. 2001 Interest expense increased $313 million in 2002. An increase in the average debt balance outstanding from $3 billion in 2001 to $8.3 billion in 2002 caused interest expense to increase $319 million. The increase in average debt outstanding was attributable primarily to the long-term debt issued and assumed as a result of the Mitchell and Anderson acquisitions.

The average interest rate on outstanding debt decreased from 6.6% in 2001 to 6% in 2002 due to the favorable rates on the borrowings under the $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. Items not related to the balance of debt outstanding include early retirement premiums, facility and agency fees, amortization of costs and other miscellaneous items. 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 and Anderson acquisitions.

2001 vs. 2000 Interest expense increased $65 million in 2001. Of this total increase, $44 million was caused by an increase in the average debt balance outstanding from $2.3 billion in 2000 to $3 billion in 2001. The increase in average debt outstanding was attributable primarily to the long-term debt issued and assumed as a result of the October 2001 Anderson acquisition.

The average interest rate on outstanding debt decreased from 6.7% in 2000 to 6.6% in 2001. This rate decrease caused interest expense to decrease $1 million in 2001. Other items included in interest expense that are not related to the debt balance outstanding were $22 million higher in 2001 compared to 2000. The increase in other items was primarily related to an increase in accretion of discounts and a $7 million loss related to an early retirement premium.

The increase in accretion of debt discounts in 2001 was related to the adoption of SFAS No. 133 effective January 1, 2001. Devon's debentures that are exchangeable into shares of ChevronTexaco Corporation ("ChevronTexaco") common stock were revalued as of August 17, 1999. This is the date the debentures were assumed as part of the PennzEnergy merger. Under SFAS No. 133, the total fair value of the debentures was allocated between the interest-bearing debt and the option to exchange ChevronTexaco common stock that is embedded in the debentures. Accordingly, the debt portion of the debentures was reduced by $140 million as of August 17, 1999. This discount is being accreted in interest expense, which has raised the effective interest rate on the debentures to 7.76% in 2001 compared to 4.92% recorded prior to 2001. The accretion in 2001 was $12 million.

Effects of Changes in Foreign Currency Exchange Rates 2002 vs. 2001 As a result of the Anderson acquisition, a Canadian subsidiary has $400 million of fixed-rate senior notes 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 acquired to the dates of repayment increase or decrease the expected amount of Canadian dollars eventually required to repay the notes. 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. The increase in the Canadian-to-U.S. dollar exchange rate from $0.628 at December 31, 2001 to $0.633 at December 31, 2002 resulted in a $1 million gain. The drop in the Canadian-to-U.S. dollar exchange rate from $0.642 at October 15, 2001 (when the debt was assumed) to $0.628 at December 31, 2001, resulted in an $11 million loss.

2001 vs. 2000 Until mid-January 2000, a Canadian subsidiary had certain fixed-rate senior notes which were denominated in U.S. dollars. In mid-January 2000, these notes were retired prior to maturity. The Canadian-to-U.S. dollar exchange rate dropped slightly in January prior to the debt retirement. As a result, $3 million of expense was recognized in 2000.

Change in Fair Value of Financial Instruments 2002 vs. 2001 As required under the provisions of SFAS No. 133, Accounting for Derivative Instruments and Certain Hedging Activities and SFAS No. 138, Accounting for Certain Derivative Instruments and Certain Hedging Activities, an Amendment of SFAS No. 133, we record in our statements of operations the change in fair value of derivative instruments that do not qualify for hedge accounting treatment.

During 2002 and 2001, we recorded $20 million and $8 million, respectively, of gains related to changes in fair value. The gains related principally to the option embedded in Devon's debentures that are exchangeable into shares of ChevronTexaco common stock. We also recorded an $8 million net gain in 2002 and a $10 million net charge in 2001 related to the ineffectiveness of the various cash flow hedges.

Impairment of ChevronTexaco Corporation Common Stock Devon owns approximately 7.1 million common shares of ChevronTexaco. The market value of these shares as of December 31, 2002, was approximately $472 million. 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. The debentures, which mature in August 2008, were also assumed by Devon in the PennzEnergy acquisition.

We initially recorded the ChevronTexaco common shares at their market value at the closing date of the PennzEnergy acquisition, 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, the length of time the stock price has been below original cost and the performance of the stock price in relation to its competitors within the industry. Other factors include 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 what has ultimately become a significant decline. The price per share decreased from $88.50 at June 30, 2002, to $69.25 per share at September 30, 2002. It declined further to $66.48 per share at December 31, 2002. The year-end price of $66.48 represents a 25% decline since June 30, 2002, and a 30% decline from the original valuation in August 1999. As a result of the continuation of the decline in value during the fourth quarter of 2002, we determined that the decline is other than temporary, as 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 our results of operations in the fourth quarter of 2002. Net of the applicable tax benefit, the charge reduced our net earnings by $128 million.

Depending on the future performance of ChevronTexaco's common stock, we may be required to record additional noncash charges in future periods if we determine that a decline in the value of such stock is other than temporary.

Other Income 2002 vs. 2001 Other income decreased $35 million, or 51% in 2002. Other income in 2001 included a $30 million gain from the settlement of a foreign exchange forward purchase contract we entered into related to the funding of the Anderson acquisition. This gain did not recur in 2002.

2001 vs. 2000 Other revenues increased $29 million, or 73% in 2001. As discussed previously, 2001 other income included a $30 million gain from the settlement of a foreign exchange forward purchase contract entered into by Devon related to the funding of the Anderson acquisition.

Income Taxes 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.

2001 vs. 2000 Devon's 2001 and 2000 effective financial tax expense rates were 18% and 36%, respectively. Excluding the effects of the reduction of carrying value of oil and gas properties in 2001, the effective financial tax expense rate was 37% in 2001. The 2001 rate was higher than the statutory federal tax rate of 35% due to the effect of state taxes, goodwill amortization that was not deductible for income tax purposes and the effect of foreign income taxes. The 2000 rate 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, offset in part by the recognition of a benefit from the disposition of Devon's assets in Venezuela.

Results of Discontinued Operations Effective January 1, 2002, Devon was required to adopt SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets. It supersedes both SFAS No. 121, Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of and the accounting and reporting provisions of APB Opinion No. 30, Reporting the Results of Operations-Reporting the Effects of Disposal of a Segment of a Business, and Extraordinary, Unusual and Infrequently Occurring Events and Transactions, for the disposal of a segment of a business (as previously defined in that Opinion).

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, we reclassified our 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.

Following are the components of the net results of discontinued operations for the years 2002, 2001 and 2000:

		2002	2001	2000
			(IN MILLIONS)	
Net gain on sale of discontinued operations	$	31	--	--
Earnings from discontinued operations before income taxes		23	56	104
Income tax expense		9	25	35
Net results of discontinued operations	$	45	31	69

2002 vs. 2001 The decrease in earnings from discontinued operations before income taxes and the related income taxes from 2001 to 2002 was primarily due to the sale of these operations during 2002.

2001 vs. 2000 The decrease in earnings from discontinued operations before income taxes and the related income taxes from 2000 to 2001 was primarily due to a decline in oil prices and the recognition of a $24 million reduction in the carrying value of Egyptian oil and gas properties. The reduction in Egypt was the result of high finding and development costs and negative revisions to proved reserves.

Cumulative Effect of Change in Accounting Principle At the time of adoption of SFAS No. 133, Devon 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 Approximately $3.4 billion was spent in 2002 for capital expenditures. This total includes $1.7 billion related to the January 2002 Mitchell acquisition; $1.6 billion for other acquisitions and the drilling or development of oil and gas properties; and $0.1 billion related to marketing and midstream assets. These amounts compare to 2001 total expenditures of $5.2 billion ($3.5 billion of which related to the October 2001 Anderson acquisition and $1.6 billion of which was related to other acquisitions and the drilling or development of oil and gas properties) and 2000 total expenditures of $1.1 billion ($1 billion of which was related to the drilling or development of oil and gas properties).

Other Cash Uses Devon's common stock dividends were $31 million, $25 million and $22 million in 2002, 2001 and 2000, respectively. Devon also paid $10 million of preferred stock dividends in 2002, 2001 and 2000.

During 2001, we repurchased 3,754,000 shares of common stock at an aggregate cost of $190 million or $50.71 per share. We also repurchased shares of our 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.

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

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 our control and are difficult to predict.

To mitigate some of the risk inherent in oil and natural gas prices, Devon has entered into various fixed-price physical delivery contracts and financial price swap contracts to fix the price to be received for a portion of future oil and natural gas production. Additionally, Devon has utilized price collars to set minimum and maximum prices on a portion of its production. The table below provides the volumes associated with these various arrangements as of January 31, 2003.

	FIXED-PRICE PHYSICAL DELIVERY CONTRACTS	PRICE SWAP CONTRACTS	PRICE COLLARS	TOTAL
Oil production (MMBbls)				
2003	--	--	20	20
2004	--	--	1	1
Natural gas production (Bcf)				
2003	16	35	239	290
2004	16	--	47	63

In addition to the above quantities, Devon also has fixed-price physical delivery contracts, for the years 2005 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 yearly 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 negative effect of declining prices on our operating cash flow. The combination of fixed-price contracts, price swaps and price collars currently in place represents approximately 55% of estimated 2003 oil production and 39% of estimated 2003 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 December 2002, Devon announced that its capital expenditure budget for the year 2003 was approximately $1.8 billion. This capital budget 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, we could choose to defer a portion of these planned 2003 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 2003, Devon anticipates that its operating cash flow will exceed its planned capital expenditures and other cash requirements for the year. We currently intend 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. On June 7, 2002, Devon renewed the $800 million, 364-day portion of its 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 5, 2003 (the "Tranche B Revolving Period"). We 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 6, 2003, at the end of the Tranche B Revolving Period, Devon may convert the then outstanding balance under the Tranche B facility to a two-year term loan by paying the Agent a fee of 12.5 basis points. The applicable borrowing rate would be at LIBOR plus 125 basis points. On December 31, 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, 2002, net of $25 million of outstanding letters of credit, was $700 million.

We may borrow funds under the $275 million Canadian Facility until June 5, 2003 (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, 2002, there were no borrowings under the $275 million Canadian Facility.

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 we may elect for periods up to six months. Devon has historically elected a rate that is based upon LIBOR, plus a margin dictated by our debt rating. Borrowings under the Canadian Facility have also been made under a rate based upon the Bankers' Acceptance rate, plus a margin dictated by Devon's debt rating. Based upon our current debt rating, Devon can borrow under the Credit Facilities at a rate of between 45 and 125 basis points above LIBOR based upon usage and the tranche utilized, and 72.5 basis points above the Bankers' Acceptance rate. The Credit Facilities also provide for an annual facility fee of $1.4 million that is payable quarterly.

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. We had no commercial paper debt outstanding at December 31, 2002.

On July 25, 2002, Devon renewed and increased its letter of credit and revolving bank facility ("LOC Facility") for its Canadian operations. This C$150 million LOC Facility will be used primarily by Devon's wholly-owned subsidiaries, Devon Canada Corporation and Northstar Energy Corporation, to issue letters of credit. As of December 31, 2002, C$109 million ($69 million converted to U.S. dollars using the December 31, 2002, exchange rate) of letters of credit were issued under the LOC Facility primarily for Canadian drilling commitments.

A portion of cash used in the Anderson and Mitchell acquisitions was provided by a $3 billion senior unsecured credit facility. This credit facility, which was entered into in October 2001, has a term of five years. The $3 billion credit facility was fully borrowed upon the closing of the Mitchell acquisition on January 24, 2002. However, as of December 31, 2002, $1.9 billion of the balance had been retired.The primary sources of the repayments were the issuance of $1 billion of debt securities, of which $0.8 billion was used to pay down debt, and $1.4 billion from the sale of certain oil and gas properties, of which $1.1 billion was used to pay down debt.

The remaining balance outstanding as of December 31, 2002, will mature as follows:

	(IN MILLIONS)
April 15, 2006	$ 335
October 15, 2006	800
	$ 1,135

This $3 billion facility includes various rate options which can be elected by Devon, including a rate based on LIBOR plus a margin. Through June 17, 2002, this margin was fixed at 100 basis points. Thereafter, the margin is based on our debt rating. Based on our current debt rating, the margin after June 17, 2002, is 100 basis points. As of December 31, 2002, the average interest rate on this facility was 2.5%.

Devon's Credit Facilities and its $3 billion term loan credit facility each 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 Corporation 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, 2002, our ratio of total funded debt to total capitalization, as defined in its credit agreements, was 55.0%.

Our access to funds from our 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 our Credit Facilities and the $3 billion term loan credit facility include covenants that require us to report a condition or event having a material adverse effect on the company, the obligation of the banks to fund the Credit Facilities is not conditioned on the absence of a material adverse effect.

Long-Term Debt Securities

On March 25, 2002, Devon sold $1 billion of 7.95% notes due April 15, 2032. The net proceeds received, after discounts and issuance costs, were $986 million. The debt securities are unsecured and unsubordinated obligations of Devon. The net proceeds 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.

Debt Ratings

We receive 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 and 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 us 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.

As summarized earlier in this section, Devon's cost of borrowing under its Credit Facilities and 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 $3 billion term loan facility would increase from LIBOR plus 100 basis points to LIBOR plus 125 basis points. A ratings downgrade could also adversely impact Devon's ability to economically access future debt markets.

As of January 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, 2002, is provided in the following table.

		PAYMENTS DUE BY YEAR						
		2003	2004	2005	2006	2007	AFTER 2007	TOTAL
					(IN MILLIONS)			
Long-term debt	$	--	336	347	1,262	--	5,725	7,670
Operating leases		30	33	28	24	20	86	221
Drilling obligations		151	34	37	1	--	--	223
Firm transportation agreements		97	83	61	52	45	221	559
Total	$	278	486	473	1,339	65	6,032	8,673

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.

The above table does not include $94 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 our Canadian drilling commitments ($40 million of which are included in the above table). The $7.7 billion of long-term debt shown in the table excludes $113 million of discounts and a $5 million fair value adjustment. Both of these items are included in the December 31, 2002, book balance of the debt.

Pension Obligations

Devon accounts for its defined benefit pension plans using SFAS No. 87, Employer's Accounting for Pensions. Under SFAS 87, pension expense is recognized on an accrual basis over employees' approximate service periods. Pension expense calculated under SFAS 87 is generally independent of funding decisions or requirements. Devon recognized expense for its defined benefit pension plans of $16 million, $7 million, and $5 million in 2002, 2001 and 2000, respectively. Devon estimates that its pension expense will approximate $30 million in 2003.

As compared to the "projected benefit obligation," Devon's qualified and nonqualified defined benefit plans were underfunded by $179 million and $54 million at December 31, 2002, and 2001, respectively. The increase in the underfunded amount during 2002 was primarily caused by additional underfunded obligations assumed in the January 2002

Mitchell acquisition, losses on investments and actuarial losses. A detailed reconciliation of the 2002 activity is included in Note 10 to the accompanying consolidated financial statements. Of the $179 million underfunded status at the end of 2002, $75 million is attributable to various nonqualified defined benefit plans which have no plan assets. However, certain trusts have been established to assist Devon in funding the benefit obligations of such nonqualified plans. As of December 31, 2002, these trusts had investments with a market value of $53 million. The value of these trusts is included in noncurrent other assets in Devon's accompanying consolidated balance sheet.

As compared to the "accumulated benefit obligation," Devon's qualified defined benefit plans were underfunded by $82 million at December 31, 2002. The accumulated benefit obligation differs from the projected benefit obligation in that the former includes no assumption about future compensation levels. Our current intentions are to fund this accumulated benefit obligation deficit over the two-year period ending December 31, 2004. 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. We believe that the two most critical assumptions affecting pension expense and liabilities are the expected long-term rate of return on plan assets and the assumed discount rate.

Devon assumed its plan assets would generate a long-term weighted average rate of return of 8.27% at December 31, 2002 and 2001, and 8.5% at December 31, 2000. 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 mix for Devon's plan assets are approximately 65% domestic equities, 15% international equities and 20% fixed income instruments.

We believe that our 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 8.27% to 7.27%) would increase the expected 2003 pension expense by approximately $3 million.

Devon discounted its future pension obligations using a weighted average rate of 6.72% at December 31, 2002, compared to 7.10% at December 31, 2001, and 7.65% at December 31, 2000. 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 6.72% to 6.47%) would increase Devon's pension liability at December 31, 2002, by approximately $14 million, and increase its estimated 2003 pension expense by approximately $2 million.

At December 31, 2002, we had unrecognized actuarial losses of $152 million. These losses will be recognized as a component of pension expense in future years. Devon estimates that approximately $10 million, $9 million and $8 million of the unrecognized actuarial losses will be included in pension expense in 2003, 2004 and 2005, respectively. The $10 million estimated to be recognized in 2003 is a component of the total estimated 2003 pension expense of $30 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. We cannot predict with certainty what these factors will be in the future.

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 14 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 3% 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 our assessment of future prices or costs, but rather 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, Devon does not 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. On any particular day at the end of a quarter, prices 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.

We recorded writedowns to our Canadian oil and gas properties as of June 30, 2002. Based on oil and natural gas 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 Devon's 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.

We also recorded writedowns to our domestic and Canadian oil and gas properties as of December 31, 2001. The domestic properties were reduced by $449 million and the Canadian properties were reduced by $434 million. 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.

If oil or gas prices at the end of future quarters drop below these June 30, 2002, or December 31, 2001, prices, or if Devon reduces its estimates of proved reserve quantities, further writedowns would likely occur.

Fair Values of Derivative Instruments The estimated fair values of Devon's derivative instruments are recorded on Devon's consolidated balance sheets. Substantially all of Devon's derivative instruments represent hedges of the price of future oil and natural gas production. 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 hedging instruments are recorded directly to stockholders' equity until the hedged oil or natural gas quantities are produced.

The estimates of the fair values of our hedging derivatives require substantial judgment. Devon obtains 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, and the resulting estimated future cash inflows or outflows over the lives of the hedges are discounted using our current borrowing rates under our revolving credit facilities. In addition, Devon estimates 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.

As stated earlier, substantially all of our derivative instruments are hedges of the price of future oil and natural gas production. Devon is not involved in any speculative trading activities of derivatives.

Business Combinations We have grown substantially during recent years through acquisitions of other oil and natural gas companies. Most of these acquisitions have been accounted for using the purchase method of accounting. 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. As of January 1, 2002, accounting for goodwill changed. In prior years, goodwill was amortized over its estimated useful life. As of 2002, goodwill is no longer amortized, but instead 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. Devon's estimates of future prices are based on its own analysis of pricing trends. These estimates are based on current data obtained with regard to regional and worldwide supply and demand dynamics such as economic growth forecasts. They are also based on industry data regarding natural gas storage availability, drilling rig activity, changes in delivery capacity, trends in regional pricing differentials and other fundamental analysis. Future price forecasts from independent third parties are noted when Devon makes its pricing estimates.

Our estimates of future prices are applied to the estimated reserve quantities acquired to arrive at estimates of future net revenues. For estimated proved reserves, the future net revenues are then discounted using a rate determined appropriate at the time of the business combination based upon our cost of capital.

Devon also applies these same general principles in arriving at the fair value of unproved reserves acquired in a business combination. These unproved reserves are generally classified as either probable or 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 Devon considers 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, and 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.

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

Because the Mitchell marketing and midstream assets primarily served gas producing properties that were also acquired by Devon from Mitchell, certain of the assumptions regarding future operations of the gas producing properties were also integral to the value of the marketing and 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 our estimated fair value of the marketing and midstream facilities and equipment.

Valuation of Goodwill Effective January 1, 2002, we adopted the remaining provisions of SFAS No. 142, Goodwill and Other Intangible Assets. Under SFAS No. 142, goodwill and intangible assets with indefinite useful lives are no longer amortized, but are instead 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.

Impact of Recently Issued Accounting Standards Not Yet Adopted In June 2001, the FASB issued SFAS No. 143, Accounting for Asset Retirement Obligations. SFAS No. 143 requires liability recognition for retirement obligations associated with tangible long-lived assets. These include 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 for settlement. The initial measurement of the asset retirement obligation is to be the discounted present fair value of the obligation. This is defined as “the price that an entity would have to pay a willing third party of comparable credit standing to assume the liability in a current transaction other than in a forced or liquidation sale.”

The asset retirement cost equal to the discounted fair value of the retirement obligation is to be capitalized as part of the cost of the related long-lived asset and allocated to expense using a systematic and rational method.

Devon will adopt SFAS No. 143 effective January 1, 2003 using a cumulative effect approach to recognize transition amounts for asset retirement obligations, asset retirement costs and accumulated depreciation.

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 of SFAS No. 143 on January 1, 2003, Devon expects to record a cumulative-effect-type adjustment for an increase to net earnings of between $10 million and $30 million, net of deferred tax expense of between $5 million and $15 million. Additionally, Devon expects to establish an asset retirement obligation of between $425 million and $475 million, an increase to property and equipment of between $375 million and $425 million and a decrease in accumulated DD&A of between $65 million and $95 million.

The FASB issued Statement No. 145, Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections, on April 30, 2002. SFAS No. 145 will be effective for fiscal years beginning after May 15, 2002. This statement rescinds SFAS No. 4, Reporting Gains and Losses From Extinguishment of Debt, and requires that all gains and losses from extinguishment of debt should be classified as extraordinary items only if they meet the criteria in APB No. 30. Applying APB No. 30 will distinguish transactions that are part of an entity’s recurring operations from those that are unusual or infrequent or that meet the criteria for classification as an extraordinary item. Any gain or loss on extinguishment of debt that was classified as an extraordinary item in prior periods presented that does not meet the criteria in APB No. 30 for classification as an extraordinary item must be reclassified. Devon early adopted the provisions related to SFAS No. 145 during the fourth quarter 2002. With the adoption of SFAS No. 145, a loss of $6 million resulting from extinguishment of debt in 1999 was reclassified from extraordinary loss to interest expense. Also, 1999’s current income tax expense was reduced by the $2 million tax benefit related to the loss from early extinguishment.

The FASB issued Statement No. 146, Accounting for Costs Associated with Exit or Disposal Activities, in June 2002. SFAS No. 146 addresses financial accounting and reporting for costs associated with exit or disposal activities and nullifies Emerging Issues Task Force Issue No. 94-3, Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs incurred in a Restructuring) SFAS No. 146 applies to costs incurred in an “exit activity,” which includes, but is not limited to, a restructuring, or a “disposal activity” covered by SFAS No. 144.

SFAS No. 146 requires that a liability for a cost associated with an exit or disposal activity be recognized when the liability is incurred. Previously, under Issue 94-3, a liability for an exit cost was recognized at the date of an entity’s commitment to an exit plan. Statement No. 146 also establishes that fair value is the objective for initial measurement of the liability.

The provisions of SFAS No. 146 are effective for exit or disposal activities that are initiated after December 31, 2002. Devon currently has no such exit or disposal activities planned.

In November 2002, the FASB issued Interpretation No. 45, Guarantor’s Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness to Others, an interpretation of FASB Statements No. 5, 57 and 107 and a rescission of FASB Interpretation No. 34. This Interpretation elaborates on the disclosures to be made by a guarantor in its interim and annual financial statements about its obligations under guarantees issued. The Interpretation also clarifies that a guarantor is required to recognize, at inception of a guarantee, a liability for the fair value of the obligation undertaken. The initial recognition and measurement provisions of the Interpretation are applicable to guarantees issued or modified after December 31, 2002, and are not expected to have a material effect on Devon’s financial statements. The disclosure requirements are effective for financial statements of interim and annual periods ending after December 31, 2002 and are included in the notes to the accompanying consolidated financial statements.

In December 2002, the FASB issued SFAS No. 148, Accounting for Stock-Based Compensation – Transition and Disclosure, an amendment of FASB Statement No. 123. This Statement amends FASB Statement No. 123, Accounting for Stock-Based Compensation, to provide alternative methods of transition for a voluntary change to the fair value method of accounting for stock-based employee compensation. In addition, this Statement amends the disclosure requirements of Statement No. 123 to require prominent disclosures in both annual and interim financial statements. Certain of the disclosure modifications are required for fiscal years ending after December 15, 2002 and are included in the notes to the accompanying consolidated financial statements.

In January 2003, the FASB issued Interpretation No. 46, Consolidation of Variable Interest Entities, an Interpretation of Accounting Research Bulletin No. 51. Interpretation No. 46 requires a company to consolidate a variable interest entity if the company has a variable interest (or combination of variable interests) that will absorb a majority of the entity’s expected losses if they occur, receive a majority of the entity’s expected residual returns if they occur, or both. A direct or indirect ability to make decisions that significantly affect the results of the activities of a variable interest entity is a strong indication that a company has one or both of the characteristics that would require consolidation of the variable interest entity. Interpretation No. 46 also requires additional disclosures regarding variable interest entities. The new interpretation is effective immediately for variable interest entities created after January 31, 2003, and is effective in the first interim or annual period beginning after June 15, 2003, for variable interest entities in which a company holds a variable interest that it acquired before February 1, 2003. We own no interests in variable interest entities, and therefore this new interpretation will not affect our consolidated financial statements.

2003 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, 2002, reserve reports of independent petroleum engineers 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 and drilling risks. Risks also include 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 our control and are difficult to predict. In addition to volatility in general, our 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, 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 2003 will be substantially similar to those of 2002, unless otherwise noted.

Given the general limitations expressed herein, following are our forward-looking statements for 2003. 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 an exchange rate of $0.65 U.S. dollar to $1.00 Canadian dollar. The actual 2003 exchange rate may vary materially from this estimated rate. Such variations could have a material effect on the following estimates.

Though we have completed several major property acquisitions and dispositions in recent years, these transactions are opportunity driven. Thus,Devon does not "budget," nor can it reasonably predict, the timing or size of such possible acquisitions or dispositions, if any. As discussed in Note 16 to the accompanying consolidated financial statements, on February 24, 2003, Devon announced its intent to merge with Ocean Energy Inc. ("Ocean"). The following forward-looking estimates do not include the additional revenues and expenses that Devon will report in 2003 if this merger is consummated.

Geographic Reporting Areas for 2003 The following estimates of production, average price differentials and capital expenditures are provided separately for each of the following geographic areas:

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

Oil, Gas and NGL Production Set forth in the following paragraphs are individual estimates of Devon's oil, gas and NGL production for 2003. On a combined basis, Devon estimates its 2003 oil, gas and NGL production will total between 178.1 and 186.9 MMBoe. Of this total, approximately 92% is estimated to be produced from reserves classified as "proved" at December 31, 2002.

Oil Production Devon expects its oil production in 2003 to total between 35.4 and 37.2 MMBbls. Of this total, approximately 92% is estimated to be produced from reserves classified as "proved" at December 31, 2002. The expected ranges of production by area are as follows:

	(MMBBLS)
United States	19.1 to 20.1
Canada	13.5 to 14.2
International	2.8 to 2.9

Oil Prices – Floating Devon's 2003 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	($3.00) to ($2.00)
Canada	($6.25) to ($4.25)
International	($2.80) to ($1.80)

Devon has also entered into costless price collars that set a floor and ceiling price for a portion of its 2003 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. If the NYMEX 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 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.

To simplify presentation, we have aggregated costless collars as of January 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.

		WEIGHTED AVERAGE		
AREA (RANGE OF FLOOR PRICES/CEILING PRICES)	BBLS/DAY	FLOOR PRICE PER BBL	CEILING PRICE PER BBL	MONTHS OF PRODUCTION
United States ($20.00 - $22.75/$27.05 - $28.65)	18,000	$ 21.65	$ 27.91	Jan – Dec
United States ($23.25 - $23.50/$28.25 - $30.00)	8,000	$ 23.38	$ 29.12	Jan – Dec
United States ($23.50 - $23.50/$28.25 - $30.75)	6,000	$ 23.50	$ 29.31	Jul – Dec
Canada ($20.00 - $21.00/$26.60 - $28.15)	5,000	$ 20.40	$ 27.37	Jan – Dec
Canada ($22.00 - $22.75/$27.00 - $28.40)	13,000	$ 22.29	$ 27.52	Jan – Dec
Canada ($23.25 - $23.50/$28.35 - $29.25)	5,000	$ 23.30	$ 28.79	Jan – Dec
Canada ($23.50 - $23.50/$28.80 - $29.75)	3,000	$ 23.50	$ 29.18	Jul – Dec

Gas Production We expect our 2003 gas production to total between 731 Bcf and 767 Bcf. Of this total, approximately 91% is estimated to be produced from reserves classified as "proved" at December 31, 2002. The expected ranges of production by area are as follows:

	(BCF)
United States	472 to 495
Canada	259 to 272

Gas Prices – Fixed Through various price swaps and fixed-price physical delivery contracts, Devon has fixed the price it will receive in 2003 on a portion of its 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	97,148	$ 3.23	Jan – Dec
Canada	43,578	$ 2.30	Jan – Jun
Canada	43,578	$ 2.29	Jul – Dec

Gas Prices – Floating For the natural gas production for which prices have not been fixed, Devon's 2003 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 represented by 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	($0.80) to ($0.30)
Canada	($0.90) to ($0.40)

Devon has also entered into costless price collars that set a floor and ceiling price for a portion of its 2003 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 January 31, 2003, 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 prices shown in the following table have been adjusted to a NYMEX-based price, using our estimates of 2003 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.

		WEIGHTED AVERAGE		
AREA (RANGE OF FLOOR PRICES/CEILING PRICES)	MMBTU/DAY	FLOOR PRICE PER MMBTU	CEILING PRICE PER MMBTU	MONTHS OF PRODUCTION
United States ($3.28 - $3.28/$6.23 - $6.53)	40,000	$ 3.28	$ 6.38	Jan – Dec
United States ($3.28 - $3.28/$5.53 - $5.93)	55,000	$ 3.28	$ 5.74	Jan – Dec
United States ($3.25 - $3.28/$4.65 - $4.93)	70,000	$ 3.27	$ 4.80	Jan – Dec
United States ($3.00 - $3.28/$4.05 - $4.20)	130,000	$ 3.12	$ 4.11	Jan – Dec
United States ($3.28 - $3.45/$4.20 - $4.49)	110,000	$ 3.35	$ 4.37	Jan – Dec
United States ($3.44 - $3.44/$6.69 - $6.69)	5,000	$ 3.44	$ 6.69	Apr – Sep
Canada ($3.28 - $3.39/$6.85 - $7.13)	20,000	$ 3.34	$ 6.99	Jan – Dec
Canada ($3.38 - $3.57/$6.10 - $6.89)	80,000	$ 3.49	$ 6.52	Jan – Dec
Canada ($3.45 - $3.52/$4.27 - $4.89)	90,000	$ 3.48	$ 4.34	Jan – Dec
Canada ($3.66 - $3.67/$7.24 - $7.68)	30,000	$ 3.66	$ 7.44	Apr – Oct
Canada ($3.53 - $3.54/$5.27 - $5.96)	40,000	$ 3.54	$ 5.60	Jan – Dec

NGL Production Devon expects its 2003 production of NGLs to total between 20.9 MMBbls and 21.9 MMBbls. Of this total, 96% is estimated to be produced from reserves classified as "proved" at December 31, 2002. The expected ranges of production by area are as follows:

	(MMBBLS)
United States	16.6 to17.4
Canada	4.3 to 4.5

Marketing and Midstream Revenues and Expenses Devon's marketing and midstream revenues and expenses are derived primarily from its 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 agreements, and the amount of repair and workover activity required to maintain anticipated processing levels.

These factors, coupled with uncertainty of future natural gas and NGL prices, increase the uncertainty inherent in estimating future marketing and midstream revenues and expenses. Given these uncertainties, we estimate that 2003 marketing and midstream revenues will be between $1.18 billion and $1.25 billion and marketing and midstream expenses will be between $961 million and $1.02 billion.

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, Devon estimates that 2003 lease operating expenses will be between $611 million and $649 million and transportation costs will be between $141 million and $150 million. We estimate that production taxes will be between 3.7% and 4.2% 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 2003 oil and gas property DD&A rate will depend on various factors. Most notable among such factors is the amount of proved reserves that will be added from drilling or acquisition efforts in 2003 compared to the costs incurred for such efforts, and the revisions to Devon's year-end 2002 reserve estimates that, based on prior experience, are likely to be made during 2003.

Based on these uncertainties, oil and gas property related DD&A expense for 2003 is expected to be between $1.1 billion and $1.2 billion. Additionally, Devon expects its DD&A expense related to non-oil and gas property fixed assets to total between $124 million and $132 million. This range includes $78 million to $83 million related to marketing and midstream assets. Based on these DD&A amounts and the production estimates set forth earlier, Devon expects its consolidated DD&A rate will be between $6.82 per Boe and $7.22 per Boe.

Accretion of Asset Retirement Obligation As discussed in the previous section titled "Impact of Recently Issued Accounting Standards Not Yet Adopted," Devon adopted SFAS No. 143 effective January 1, 2003 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 for settlement. The initial measurement of the asset retirement obligation is to be the discounted present fair value, defined as "the price that an entity would have to pay a willing third party of comparable credit standing to assume the liability in a current transaction other than in a forced or liquidation sale." Because the asset retirement obligation is a discounted value, accretion will be recognized as the estimated date for settling the obligation draws closer.

As a result of the requirements of SFAS No. 143, Devon expects its 2003 accretion of its asset retirement obligation related to the adoption of SFAS 143 to be between $25 million and $35 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 Devon's 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 2003 is expected to be between $215 million and $229 million.

Interest Expense Future interest rates, debt outstanding and oil, natural gas and NGL prices have a significant effect on Devon's interest expense. We can only marginally influence the prices we will receive in 2003 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.

Assuming no changes in fixed-rate debt balances during 2003, our average balance of fixed-rate debt during 2003 will be $6.5 billion. The interest expense in 2003 related to this fixed-rate debt, including net accretion of related discounts, will be approximately $472 million. This fixed-rate debt removes the uncertainty of future interest rates from some, but not all, of Devon's long-term debt. Our floating rate debt is discussed in the following paragraphs.

As of January 31, 2003, Devon had $1.1 billion outstanding under its original $3 billion amortizing senior unsecured term loan credit facility. This credit facility, which was entered into in October 2001, has a term of five years. This credit facility is non-revolving.

The remaining balance outstanding as of January 31, 2003, will mature as follows:

	(IN MILLIONS)
April 15, 2006	$ 335
October 15, 2006	800
	$ 1,135

This $3 billion facility includes various rate options that 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 January 31, 2003, the average interest rate on this facility was 2.3%.

From time to time, Devon borrows under its $1 billion credit facilities. Borrowings under the U.S. facility, currently set at $725 million, may be borrowed at various rate options including LIBOR plus a margin with interest periods of up to six months. Borrowings under the Canadian facility, currently set at $275 million, may be made at various rate options including LIBOR plus a margin with interest periods up to six months, or Bankers Acceptances plus a margin with interest periods of 30 to 180 days. The current LIBOR margin ranges from 45 to 125 basis points based upon usage and the tranche utilized, and the current Bankers Acceptance margin is 72.5 basis points over the cost of funding. There were no borrowings under these facilities at January 31, 2003.

We also borrow under a $150 million Canadian dollar letter of credit facility that is primarily used to issue letters of credit in association with Devon's Canadian drilling commitments. As of December 31, 2002, there were $109 million Canadian dollars of issued letters of credit under this facility. Devon may also use this facility for general corporate purposes.

From time to time, Devon also borrows under its commercial paper facility. Total borrowings under the $725 million U.S. facility and the commercial paper program cannot exceed $725 million. There were no borrowings under the commercial paper facility as of December 31, 2002. Commercial paper borrowing costs are typically 20 to 50 basis points over LIBOR. Debt outstanding under this program is generally borrowed for seven to 90-day periods, and may be borrowed up to 365 days, at prevailing commercial paper market rates.

Devon has fixed the interest rate on $125 million Canadian dollars and $50 million U.S. dollars of its floating rate debt through swap agreements at average rates of 6.4% and 5.9%, respectively. The Canadian dollar swap agreements mature at various dates through July 2007 and the U.S. dollar swap agreement matures in May 2003.

Devon has also entered into an interest rate swap on its $125 million 8.05% senior notes due in 2004 to swap a fixed interest rate for a variable interest rate. The variable interest rate on this instrument is based on LIBOR plus a margin of 336 basis points. The interest rate swap is accounted for as a fair value hedge under SFAS 133.

Our interest expense totals have historically included payments of facility and agency fees, amortization of debt issuance costs, the effect of the interest rate swaps and other miscellaneous items not related to the debt balances outstanding. We expect between $10 million and $20 million of such items to be included in our 2003 interest expense. 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 2003 interest expense will be between $512 million and $522 million.

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 (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 Devon will incur a full cost writedown in future periods.

Effects of Changes in Foreign Currency Rates Our 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 2003 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 not possible to estimate the effect which will be recorded in 2003. However, based on the January 31, 2003, Canadian-to-U.S. dollar exchange rate of $0.6540, for every $0.01 change in the exchange rate, Devon will record an effect (either income or expense) of approximately $9 million Canadian dollars. The resulting revenue or expense in U.S. dollars will depend on the currency exchange rate in effect throughout the year.

Other Revenues Devon's other revenues in 2003 are expected to be between $23 million and $26 million.

Income Taxes Devon's financial income tax rate in 2003 will vary materially depending on the actual amount of financial pre-tax earnings. The tax rate for 2003 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 2003'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 2003 will be between 20% and 40%. The current income tax rate is expected to be between 0% and 10%. The deferred income tax rate is expected to be between 20% and 30%. 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 2003's financial income tax rates.

YEAR 2003 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, Devon does not "budget," nor can it reasonably predict, the timing or size of such possible acquisitions, if any. As discussed in Note 16 to the accompanying consolidated financial statements, on February 24, 2003, Devon announced its intention to merge with Ocean. The following forward-looking estimates do not include the additional capital expenditures that Devon will report in 2003 if this merger is consummated.

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 Devon's price expectations for its future production, some projects may be accelerated or deferred and, consequently, may increase or decrease total 2003 capital expenditures. In addition, if the actual 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 2003 capital expenditures for drilling and development efforts, plus related facilities, to total between $1.4 billion and $1.6 billion. These amounts include between $465 million and $535 million for drilling and facilities costs related to reserves classified as proved as of year-end 2002. In addition, these amounts include between $485 million and $555 million for other low risk/reward projects and between $435 million and $510 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 production facilities expenditures by geographic area.

	UNITED STATES	CANADA	INTERNATIONAL	TOTAL
		(IN MILLIONS)		
Related to Proved Reserves	$330-$370	$105-$125	$30-$ 40	$ 465-$ 535
Lower Risk/Reward Projects	$335-$375	$150-$180	$ 0-$ 0	$ 485-$ 555
Higher Risk/Reward Projects	$180-$210	$205-$235	$50-$ 65	$ 435-$ 510
Total	$845-$955	$460-$540	$80-$105	$1,385-$1,600

In addition to the above expenditures for drilling and development, Devon expects to spend between $150 million to $170 million on its marketing and midstream assets, which include its oil pipelines, gas processing plants, treating facilities and gas pipelines. We also expect to capitalize between $85 million and $95 million of G&A expenses in accordance with the full cost method of accounting. Devon also expects to pay between $30 million and $40 million for plugging and abandonment charges, and to spend between $50 million and $60 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 current $0.05 per share quarterly dividend rate and 157 million shares of common stock outstanding, 2003 dividends are expected to approximate $31 million. Also, Devon has $150 million of 6.49% cumulative preferred stock upon which it will pay $10 million of dividends in 2003.

Capital Resources and Liquidity Devon's estimated 2003 cash uses, including its drilling and development activities, are expected to be funded primarily through a combination of working capital and operating cash flow. The amount of operating cash flow to be generated during 2003 is uncertain due to the factors affecting revenues and expenses as previously cited. However, based upon current oil and gas price expectations for 2003, 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. 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. As of December 31, 2002, Devon had $975 million available under its $1 billion credit facilities, net of $25 million of outstanding letters of credit.

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 Our major market risk exposure is in the pricing applicable to our oil, gas and NGLs 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 NGLs production. Pricing for oil and gas 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, natural gas and NGLs 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 as of January 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 natural gas production in 2003. These swaps will result in a fixed price of $3.23 per Mcf on 97,148 Mcf per day of domestic production during 2003. Where necessary, the 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.

Costless Price Collars Devon has also entered into costless price collars that set a floor and ceiling price for a portion of its 2003 and 2004 oil and natural gas production. The following tables include information on these collars for each geographic area. The floor and ceiling prices related to domestic oil production are based on NYMEX. The NYMEX price is the monthly average of settled prices on each trading day for West Texas Intermediate Crude oil delivered at Cushing, Oklahoma. The gas prices shown in the following table have been adjusted to a NYMEX-based price, using Devon's estimates of 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.

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 oil or 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 content of gas production, 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.

The floor and ceiling prices in the following tables are weighted averages of all the various collars.

OIL PRODUCTION

	2003			
		WEIGHTED AVERAGE		
AREA (RANGE OF FLOOR PRICES/CEILING PRICES)	BBLS/DAY	FLOOR PRICE PER BBL	CEILING PRICE PER BBL	MONTHS OF PRODUCTION
United States ($20.00 - $22.75/$27.05 - $28.65)	18,000	$ 21.65	$ 27.91	Jan – Dec
United States ($23.25 - $23.50/$28.25 - $30.00)	8,000	$ 23.38	$ 29.12	Jan – Dec
United States ($23.50 - $23.50/$28.25 - $30.75)	6,000	$ 23.50	$ 29.31	Jul – Dec
Canada ($20.00 - $21.00/$26.60 - $28.15)	5,000	$ 20.40	$ 27.37	Jan – Dec
Canada ($22.00 - $22.75/$27.00 - $28.40)	13,000	$ 22.29	$ 27.52	Jan – Dec
Canada ($23.25 - $23.50/$28.35 - $29.25)	5,000	$ 23.30	$ 28.79	Jan – Dec
Canada ($23.50 - $23.50/$28.80 - $29.75)	3,000	$ 23.50	$ 29.18	Jul – Dec

	2004			
		WEIGHTED AVERAGE		
AREA (RANGE OF FLOOR PRICES/CEILING PRICES)	BBLS/DAY	FLOOR PRICE PER BBL	CEILING PRICE PER BBL	MONTHS OF PRODUCTION
United States ($20.00 - $20.00/$26.50 - $28.00)	2,000	$ 20.00	$ 27.25	Jan – Dec
Canada ($20.00 - $20.00/$26.50 - $27.00)	2,000	$ 20.00	$ 26.75	Jan – Dec

GAS PRODUCTION

	2003			
		WEIGHTED AVERAGE		
AREA (RANGE OF FLOOR PRICES/CEILING PRICES)	MMBTU/DAY	FLOOR PRICE PER MMBTU	CEILING PRICE PER MMBTU	MONTHS OF PRODUCTION
United States ($3.28 - $3.28/$6.23 - $6.53)	40,000	$ 3.28	$ 6.38	Jan – Dec
United States ($3.28 - $3.28/$5.53 - $5.93)	55,000	$ 3.28	$ 5.74	Jan – Dec
United States ($3.25 - $3.28/$4.65 - $4.93)	70,000	$ 3.27	$ 4.80	Jan – Dec
United States ($3.00 - $3.28/$4.05 - $4.20)	130,000	$ 3.12	$ 4.11	Jan – Dec
United States ($3.28 - $3.45/$4.20 - $4.49)	110,000	$ 3.35	$ 4.37	Jan – Dec
United States ($3.44 - $3.44/$6.69 - $6.69)	5,000	$ 3.44	$ 6.69	Apr – Sep
Canada ($3.28 - $3.39/$6.85 - $7.13)	20,000	$ 3.34	$ 6.99	Jan – Dec
Canada ($3.38 - $3.57/$6.10 - $6.89)	80,000	$ 3.49	$ 6.52	Jan – Dec
Canada ($3.45 - $3.52/$4.27 - $4.89)	90,000	$ 3.48	$ 4.34	Jan – Dec
Canada ($3.66 - $3.67/$7.24 - $7.68)	30,000	$ 3.66	$ 7.44	Apr – Oct
Canada ($3.53 - $3.54/$5.27 - $5.96)	40,000	$ 3.54	$ 5.60	Jan – Dec

	2004			
		WEIGHTED AVERAGE		
AREA (RANGE OF FLOOR PRICES/CEILING PRICES)	MMBTU/DAY	FLOOR PRICE PER MMBTU	CEILING PRICE PER MMBTU	MONTHS OF PRODUCTION
United States ($3.28 - $3.28/$5.74 - $5.81)	30,000	$ 3.28	$ 5.79	Jan – Dec
United States ($3.28 - $3.28/$6.48 - $6.48)	10,000	$ 3.28	$ 6.48	Jan – Dec
Canada ($3.65 - $3.65/$5.67 - $5.80)	20,000	$ 3.65	$ 5.73	Jan – Dec
Canada ($3.52 - $3.62/$6.55 - $6.70)	20,000	$ 3.57	$ 6.62	Jan – Dec
Canada ($3.53 - $3.56/$6.05 - $6.30)	20,000	$ 3.55	$ 6.18	Jan – Dec
Canada ($3.47 - $3.56/$7.42 - $7.70)	30,000	$ 3.50	$ 7.59	Jan – Dec

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 January 31, 2003, a 10% increase in the underlying commodities' prices would have reduced the fair value of Devon's commodity hedging instruments by $135 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.

We have fixed-price physical delivery contracts for the years 2003 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, 2002, Devon had long-term debt outstanding of $7.6 billion. Of this amount, $6.5 billion, or 85%, bears interest at fixed rates averaging 7%. The remaining $1.1 billion of debt outstanding bears interest at floating rates which averaged 2.5%.

The terms of our various floating rate debt facilities (revolving credit facilities, commercial paper and term loan credit facility) allow interest rates to be fixed at our option for periods of between seven to 180 days. A 10% increase in short-term interest rates on the floating-rate debt outstanding as of December 31, 2002 would equal approximately 25 basis points. Such an increase in interest rates would increase Devon's 2003 interest expense by approximately $3 million assuming borrowed amounts remain outstanding for all of 2003.

We assumed certain interest rate swaps as a result of the Anderson acquisition. Under these interest rate swaps, Devon has swapped a floating rate for a fixed rate. Under such swaps, Devon will record a fixed rate of 6.3% on $98 million of debt in 2003, 6.4% on $79 million of debt in 2004 through 2006 and 6.3% on $24 million of debt in 2007. The amount of gains or losses realized from such swaps are included as increases or decreases to interest expense.

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 January 31, 2003, a 10% increase in the underlying interest rates would have increased the fair value of Devon's interest rate swaps by $2 million.

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

Foreign Currency Risk 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.

As a result of the Anderson acquisition, our Canadian subsidiary, Devon Canada, assumed $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 $0.03 decrease in the Canadian-to-U.S. dollar exchange rate would cause Devon to record a charge of approximately $20 million in 2003. 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.

Devon assumed certain foreign currency exchange rate swaps in the Anderson acquisition. A portion of Devon's Canadian gas sales are based on U.S. dollar prices. Therefore, currency fluctuations between the Canadian and U.S. dollars impacts the amount of Canadian dollars received by Devon's Canadian subsidiaries for this gas production. These foreign currency exchange rate swaps mitigate the effect of volatility in the Canadian-to-U.S. dollar exchange rate on Canadian gas revenues. Under these swap agreements, in 2003, Devon will sell $12 million at average Canadian-to-U.S. exchange rates of $0.676, and buy the same amount of dollars at the floating exchange rate. The amount of gains or losses realized from such swaps are included as increases or decreases to realized gas sales. At the December 31, 2002, exchange rate, these swaps would result in a decrease to gas sales during 2003 of approximately $1 million. A further $0.03 decrease in the Canadian-to-U.S. dollar exchange rate would result in an additional decrease to 2003 gas sales of approximately $1 million.

For purposes of the sensitivity analysis described above for changes in the Canadian dollar exchange rate, a change in the rate of $0.03 was used as opposed to a 10% change in the rate. During the last 10 years, the Canadian-to-U.S. dollar exchange rate has fluctuated an average of approximately 4% per year, and no year's fluctuation was greater than 7%. The $0.03 change used in the above analysis represents an approximate 4% change in the year-end 2002 rate.

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 accounting 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, President & CEO

Brian J. Jennings
Senior Vice President

J. Michael Lacey
Senior Vice President

Duke R. Ligon
Senior Vice President

Marian J. Moon
Senior Vice President

John Richels
Senior Vice President

Darryl G. Smette
Senior Vice President

William T. Vaughn
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 (the Company) as of December 31, 2002, 2001 and 2000, and the related consolidated statements of operations, stockholders' equity and cash flows for each of the years then ended. 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, 2002, 2001 and 2000, and the results of their operations and their cash flows for each of the years then ended, 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; and, 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*; and effective January 1, 2002, adopted the remaining provisions of SFAS No. 142.

KPMG LLP

Oklahoma City, Oklahoma
February 4, 2003

CONSOLIDATED BALANCE SHEETS

DECEMBER 31, (IN MILLIONS, EXCEPT SHARE DATA)		**2002**	**2001**	**2000**
Assets				
Current assets:				
Cash and cash equivalents	$	292	183	194
Accounts receivable		639	489	562
Inventories		26	20	23
Deferred income taxes		--	--	9
Fair value of financial instruments		4	195	--
Income taxes receivable		56	68	--
Assets of discontinued operations		7	354	--
Investments and other current assets		40	45	40
Total current assets		1,064	1,354	828
Property and equipment, at cost, based on the full cost method of accounting for oil and gas properties ($2,289, $1,929 and $314 excluded from amortization in 2002, 2001 and 2000, respectively)		18,786	14,899	9,091
Less accumulated depreciation, depletion and amortization		7,934	6,137	4,429
		10,852	8,762	4,662
Investment in ChevronTexaco Corporation common stock, at fair value		472	636	599
Fair value of financial instruments		1	31	--
Goodwill		3,555	2,206	289
Assets of discontinued operations		--	--	361
Other assets		281	195	121
Total assets	$	16,225	13,184	6,860
Liabilities and Stockholders' Equity				
Current liabilities:				
Accounts payable:				
Trade		376	470	273
Revenues and royalties due to others		261	124	115
Income taxes payable		9	16	64
Accrued interest payable		119	102	23
Merger related expenses payable		12	7	52
Fair value of financial instruments		151	15	--
Liabilities of discontinued operations		--	56	--
Deferred income taxes		--	57	--
Accrued expenses		114	72	50
Total current liabilities		1,042	919	577
Other liabilities		323	172	158
Debentures exchangeable into shares of ChevronTexaco Corporation common stock		662	649	760
Other long-term debt		6,900	5,940	1,289
Deferred revenue		--	51	114
Fair value of financial instruments		18	45	--
Liabilities of discontinued operations		--	--	51
Deferred income taxes		2,627	2,149	634
Stockholders' equity:				
Preferred stock of $1 par value ($100 liquidation value) Authorized 4,500,000 shares; issued 1,500,000 in 2002, 2001 and 2000		1	1	1
Common stock of $.10 par value Authorized 400,000,000 shares; issued 160,461,000 in 2002, 129,886,000 in 2001 and 128,638,000 in 2000		16	13	13
Additional paid-in capital		5,178	3,610	3,564
Accumulated deficit		(84)	(147)	(215)
Accumulated other comprehensive loss		(267)	(28)	(85)
Unamortized restricted stock awards		(3)	--	(1)
Treasury stock, at cost: 3,704,000 shares in 2002 and 3,754,000 shares in 2001		(188)	(190)	--
Total stockholders' equity		4,653	3,259	3,277
Commitments and contingencies (Notes 11 and 12)				
Total liabilities and stockholders' equity	$	16,225	13,184	6,860

See accompanying notes to consolidated financial statements

CONSOLIDATED STATEMENTS OF OPERATIONS

YEAR ENDED DECEMBER 31, (IN MILLIONS, EXCEPT PER SHARE AMOUNTS)	2002	2001	2000
Revenues			
Oil sales	$ 909	784	906
Gas sales	2,133	1,878	1,474
NGL sales	275	131	154
Marketing and midstream revenues	999	71	53
Total revenues	4,316	2,864	2,587
Operating Costs and Expenses			
Lease operating expenses	621	467	388
Transportation costs	154	83	53
Production taxes	111	116	103
Marketing and midstream operating costs and expenses	808	47	28
Depreciation, depletion and amortization of property and equipment	1,211	831	662
Amortization of goodwill	--	34	41
General and administrative expenses	219	114	96
Expenses related to mergers	--	1	60
Reduction of carrying value of oil and gas properties	651	979	--
Total operating costs and expenses	3,775	2,672	1,431
Earnings from operations	541	192	1,156
Other Income (Expenses)			
Interest expense	(533)	(220)	(155)
Effects of changes in foreign currency exchange rates	1	(11)	(3)
Change in fair value of financial instruments	28	(2)	--
Impairment of ChevronTexaco Corporation common stock	(205)	--	--
Other income	34	69	40
Net other expenses	(675)	(164)	(118)
Earnings (loss) from continuing operations before income taxes and cumulative effect of change in accounting principle	(134)	28	1,038
Income Tax Expense (Benefit)			
Current	23	48	120
Deferred	(216)	(43)	257
Total income tax expense (benefit)	(193)	5	377
Earnings from continuing operations before cumulative effect of change in accounting principle	59	23	661
Discontinued Operations			
Results of discontinued operations before income taxes (including net gain on disposal of $31 million in 2002)	54	56	104
Income tax expense	9	25	35
Net results of discontinued operations	45	31	69
Earnings before cumulative effect of change in accounting principle	104	54	730
Cumulative effect of change in accounting principle	--	49	--
Net earnings	104	103	730
Preferred stock dividends	10	10	10
Net earnings applicable to common shareholders	$ 94	93	720
Basic net earnings per share:			
Earnings from continuing operations	$ 0.32	0.09	5.13
Net results of discontinued operations	0.29	0.25	0.53
Cumulative effect of change in accounting principle	--	0.39	--
Net earnings	$ 0.61	0.73	5.66
Diluted net earnings per share:			
Earnings from continuing operations	0.32	0.09	4.97
Net results of discontinued operations	0.29	0.25	0.53
Cumulative effect of change in accounting principle	--	0.38	--
Net earnings	$ 0.61	0.72	5.50
Weighted average common shares outstanding:			
Basic	155	128	127
Diluted	156	130	132

See accompanying notes to consolidated financial statements

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

(IN MILLIONS)		PREFERRED STOCK	COMMON STOCK	ADDITIONAL PAID-IN CAPITAL	ACCUMULATED DEFICIT	ACCUMULATED OTHER COMPRE-HENSIVE LOSS	UNAMORTIZED RESTRICTED STOCK AWARDS	TREASURY STOCK	TOTAL STOCK-HOLDERS' EQUITY
Balance as of December 31, 1999	$	1	13	3,492	(909)	(65)	--	(11)	2,521
Comprehensive earnings:									
Net earnings		--	--	--	730	--	--	--	730
Other comprehensive earnings (loss), net of tax:									
Foreign currency translation adjustments		--	--	--	--	(10)	--	--	(10)
Minimum pension liability adjustment		--	--	--	--	1	--	--	1
Unrealized loss on marketable securities		--	--	--	--	(11)	--	--	(11)
Other comprehensive loss									(20)
Comprehensive earnings									710
Stock issued		--	--	69	(4)	--	--	21	86
Stock repurchased		--	--	--	--	--	--	(10)	(10)
Tax benefit related to employee stock options		--	--	3	--	--	--	--	3
Dividends on common stock		--	--	--	(22)	--	--	--	(22)
Dividends on preferred stock		--	--	--	(10)	--	--	--	(10)
Grant of restricted stock awards		--	--	--	--	--	(5)	--	(5)
Amortization of restricted stock awards		--	--	--	--	--	4	--	4
Balance as of December 31, 2000		1	13	3,564	(215)	(85)	(1)	--	3,277
Comprehensive earnings:									
Net earnings		--	--	--	103	--	--	--	103
Other comprehensive earnings (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 earnings									57
Comprehensive earnings									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 earnings (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	1,562	--	--	--	2	1,567
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

See accompanying notes to consolidated financial statements

CONSOLIDATED STATEMENTS OF CASH FLOWS

YEAR ENDED DECEMBER 31, (IN MILLIONS)	2002	2001	2000
Cash Flows From Operating Activities			
Earnings from continuing operations	$ 59	23	661
Adjustments to reconcile earnings from continuing operations to net cash provided by operating activities:			
Depreciation, depletion and amortization of property and equipment	1,211	831	662
Amortization of goodwill	--	34	41
Accretion of discounts on long-term debt, net	33	26	3
Effects of changes in foreign currency exchange rates	(1)	11	3
Change in fair value of financial instruments	(28)	2	--
Reduction of carrying value of oil and gas properties	651	979	--
Impairment of ChevronTexaco Corporation common stock	205	--	--
Operating cash flows from discontinued operations	28	134	110
Loss (gain) on sale of assets	(2)	2	(1)
Deferred income tax expense (benefit)	(216)	(43)	257
Other	(9)	(3)	4
Changes in assets and liabilities, net of effects of acquisitions of businesses:			
(Increase) decrease in:			
Accounts receivable	(80)	203	(272)
Inventories	10	12	(5)
Income taxes receivable	--	(68)	--
Investments and other current assets	12	(8)	3
(Decrease) increase in:			
Accounts payable	(74)	37	78
Income taxes payable	21	(129)	61
Accrued interest and expenses	36	(46)	2
Deferred revenue	(46)	(63)	8
Long-term other liabilities	(56)	(24)	(26)
Net cash provided by operating activities	1,754	1,910	1,589
Cash Flows From Investing Activities			
Proceeds from sale of property and equipment	1,067	41	101
Proceeds from sale of investments	--	--	13
Capital expenditures, including acquisitions of businesses	(3,426)	(5,235)	(1,148)
Discontinued operations (including net proceeds from sale of $336 million in 2002)	316	(91)	(132)
Increase in other assets	(3)	--	(7)
Net cash used in investing activities	(2,046)	(5,285)	(1,173)
Cash Flows From Financing Activities			
Proceeds from borrowings of long-term debt, net of issuance costs	6,067	6,199	2,580
Principal payments on long-term debt	(5,657)	(2,638)	(2,952)
Issuance of common stock, net of issuance costs	32	48	51
Repurchase of common stock	--	(204)	(10)
Issuance of treasury stock	--	--	25
Dividends paid on common stock	(31)	(25)	(22)
Dividends paid on preferred stock	(10)	(10)	(10)
Decrease in long-term other liabilities	--	--	(52)
Net cash provided by (used in) financing activities	401	3,370	(390)
Effect of exchange rate changes on cash	--	(6)	(1)
Net increase (decrease) in cash and cash equivalents	109	(11)	25
Cash and cash equivalents at beginning of year	183	194	169
Cash and cash equivalents at end of year	$ 292	183	194

See accompanying notes to consolidated financial statements

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Summary Of Significant Accounting Policies

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

Basis of Presentation and Principles of Consolidation

Devon is engaged primarily in oil and gas exploration, development and production, and the acquisition of producing properties. Such activities domestically are concentrated in four geographical 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 portion 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, Brazil, China and West Africa.

Devon also has a Marketing and Midstream business unit that is 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.

Devon's share of the assets, liabilities, revenues and expenses of affiliated partnerships and the accounts of its 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. Such estimates and assumptions 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, 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 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. For the years 2002, 2001 and 2000, such internal costs capitalized totaled $97 million, $77 million and $62 million, respectively.

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 at least annually.

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 plus the estimated future expenditures (based on current costs) to be incurred in developing proved reserves, and the estimated dismantlement and abandonment costs, 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. 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 leasehold improvements, are provided using the straight-line method based on estimated useful lives from three to 39 years.

Marketable Securities and Other Investments

Devon accounts for certain investments in debt and equity securities by following the requirements of Statement of Financial Accounting Standards ("SFAS") No. 115, *Accounting for Certain Investments in Debt and Equity Securities*. This standard requires that, except for debt securities classified as "held-to-maturity," investments in debt and equity securities must be reported at fair value. As a result, Devon's investment in approximately 7.1 million shares of ChevronTexaco Corporation ("ChevronTexaco") common stock, which is classified as "available-for-sale," is reported at fair value. Except for unrealized losses that are determined to be “other than temporary,” the tax effected unrealized gain or loss is recognized in other comprehensive loss and reported as a separate component of stockholders’ equity. Devon’s investments in other short-term securities are also classified as “available-for-sale.”

The market value of Devon’s investment in ChevronTexaco as of December 31, 2002, was approximately $472 million. Devon acquired these shares in the 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.

Devon initially recorded the ChevronTexaco common shares at their market value at the closing date of the PennzEnergy acquisition, 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 what has ultimately become 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 represents a 25% decline since June 30, 2002, and a 30% decline from the original valuation in August 1999. As a result of the continuation of the decline in value during the fourth quarter of 2002, Devon determined that the decline is 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.

Depending on the future performance of ChevronTexaco’s common stock, Devon may be required to record additional noncash charges in future periods if Devon determines that a decline in the value of such stock is other than temporary.

Goodwill

Goodwill represents the excess of the purchase price of business combinations over the fair value of the net assets acquired.

Effective January 1, 2002, Devon adopted the remaining provisions of Statement of Financial Accounting Standards No. 142, Goodwill and Other Intangible Assets (SFAS No. 142). Under SFAS No. 142, goodwill and intangible assets with indefinite useful lives are no longer amortized as they were prior to 2002, 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 transition goodwill impairment assessment provisions of SFAS No. 142. Devon has completed its assessment of the fair value of its reporting units and compared such fair value to each reporting unit’s carrying value, including goodwill, as of January 1, 2002. Based on this assessment, no transitional impairment of the carrying value of goodwill was required.

As a result of the January 2002 Mitchell acquisition, goodwill increased to $3.6 billion at the end of 2002. Devon performed its annual assessment of goodwill in the fourth quarter of 2002. Based on this assessment, 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, 2000.

		FOR THE YEAR ENDED DECEMBER 31,		
		2002	2001	2000
		(IN MILLIONS, EXCEPT PER SHARE DATA)		
Net earnings applicable to common shareholders, as reported	$	94	93	720
Add back amortization of goodwill		-	34	41
Net earnings applicable to common shareholders, as adjusted	$	94	127	761
Basic earnings per share:				
Net earnings applicable to common shareholders, as reported		0.61	0.73	5.66
Amortization of goodwill		--	0.26	0.32
Net earnings applicable to common shareholders, as adjusted	$	0.61	0.99	5.98
Diluted earnings per share:				
Net earnings applicable to common shareholders, as reported		0.61	0.72	5.50
Amortization of goodwill		--	0.26	0.31
Net earnings applicable to common shareholders, as adjusted	$	0.61	0.98	5.81

Revenue Recognition and Gas Balancing

Oil and gas revenues are recognized when 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.

Hedging Activities

Devon has periodically entered into oil and gas financial instruments and foreign exchange rate swaps to manage its exposure to oil and gas price volatility. The foreign exchange rate swaps mitigate the effect of volatility in the Canadian-to-U.S. dollar exchange rate on certain Canadian gas revenues that are based on U.S. dollar prices.

As of January 1, 2001, Devon adopted the provisions of SFAS No. 133, Accounting for Derivative Instruments and Certain Hedging Activities and SFAS No. 138, Accounting for Certain Derivative Instruments and Certain Hedging Activities, an Amendment of SFAS No. 133. SFAS Nos. 133 and 138 require that all derivative instruments be recorded on the balance sheet at their respective fair values. In accordance with the transition provisions of SFAS No. 133, Devon recorded a net-of-tax cumulative-effect-type adjustment of $37 million loss in accumulated other comprehensive loss ("AOCL") to recognize the fair value of all derivatives that were designated as cash-flow hedging instruments. 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 on the balance sheet at their fair value. The majority of Devon's derivatives that qualify for hedge accounting treatment are either "cash flow" hedges or "foreign currency cash flow" hedges (collectively, "cash flow hedges"). Devon designates its cash flow hedge derivatives as such on the date the derivative contract is entered into or the date of a business combination which includes cash flow hedges. Devon formally 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.

During 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 exchange 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 usually 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 adverse effect on the value of a derivative instrument that results from a change in interest rates, commodity prices, or currency exchange rates. The market risk associated with commodity price and foreign exchange 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 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. Substantially all of Devon's commodity price swaps and costless price collars, interest rate swaps, and foreign exchange rate swaps have been designated as cash flow hedges. Changes in the fair value of these derivatives are reported on the balance sheet in AOCL. These amounts are reclassified to oil and gas sales or interest expense when the forecasted transaction takes place.

During the third quarter of 2001, Devon entered into foreign exchange forward contracts to mitigate the effect of volatility in the Canadian-to-U.S. dollar exchange rate on the Anderson acquisition. Under SFAS No. 133, these derivative instruments were not considered hedges. The realized gain of $30 million from settling these contracts is included in the 2001 consolidated statement of operations as other income.

Also, during the third quarter of 2001, Devon entered into interest rate locks to reduce exposure to the variability in market interest rates, specifically U.S. Treasury rates, in anticipation of the sale of the debt securities discussed in Note 6. These derivative instruments were designated as cash flow hedges. A $28 million loss was incurred on these interest rate locks. This loss will be amortized into interest expense using the effective interest method over the life of the debt securities.

Devon recorded in its statements of operations a gain of $28 million and a loss of $2 million for the years ended December 31, 2002 and 2001, respectively. These losses reflect the change in 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, 2002, $147 million of net deferred losses on derivative instruments accumulated in AOCL are expected to be reclassified to earnings during the next 12 months. 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 that includes the production hedged under the various derivative instruments. The maximum term over which Devon is hedging 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 would be 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 2002, 2001 and 2000 pro forma net earnings and pro forma net earnings per share would have differed from the amounts actually reported. The following table illustrates those differences.

	YEAR ENDED DECEMBER 31,		
	2002	2001	2000
	(IN MILLIONS, EXCEPT PER SHARE AMOUNTS)		
Net earnings available to common shareholders:			
As reported	$ 94	93	720
Pro forma	$ 78	79	702
Net earnings per share available to common shareholders:			
As reported:			
Basic	$ 0.61	0.73	5.66
Diluted	$ 0.61	0.72	5.50
Pro forma:			
Basic	$ 0.51	0.62	5.51
Diluted	$ 0.50	0.61	5.36

Major Purchasers

No purchaser accounted for over 10% of revenues in 2002. In 2001 and 2000, Enron Capital and Trade Resource Corporation accounted for 16% and 21%, respectively, 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.

Income Taxes

Devon accounts for income taxes using the asset and liability method. Under that method, 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. The future tax consequences attributable to the future utilization of existing tax net operating loss and other types of carryforwards are also recognized. 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 allocated to 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.

Discontinued Operations

Effective January 1, 2002, Devon was required to adopt SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets. It supersedes SFAS No. 121, Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of. It also supersedes the accounting and reporting provisions of APB Opinion No. 30, Reporting the Results of Operations-Reporting the Effects of Disposal of a Segment of a Business, and Extraordinary, Unusual and Infrequently Occurring Events and Transactions, for the disposal of a segment of a business (as previously defined in that Opinion).

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, Devon has 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.

The major classes of assets and liabilities of these discontinued operations as of December 31, 2002, 2001 and 2000 and revenues from these discontinued operations in 2002, 2001 and 2000 are presented below:

	AS OF DECEMBER 31,		
	2002	2001	2000
		(IN MILLIONS)	
Major Classes of Assets and Liabilities			
Cash	$ --	$ 10	$ 34
Accounts receivable	7	48	36
Inventories	--	21	24
Other current assets	--	2	12
Property and equipment, net of accumulated depreciation, depletion and amortization	--	266	248
Other assets	--	7	7
Total assets	$ 7	354	361
Accounts payable – trade	--	41	49
Income taxes payable	--	14	2
Accrued expense	--	1	1
Other liabilities	--	7	6
Deferred income taxes	--	(7)	(7)
Total liabilities	$ --	56	51

	FOR THE YEAR ENDED DECEMBER 31,		
	2002	2001	2000
		(IN MILLIONS)	
Revenues			
Oil sales	$ 72	174	173
Gas sales	7	12	11
NGL sales	1	1	--
Total revenues	$ 80	187	184

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) 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 2002, 2001 and 2000.

	NET EARNINGS APPLICABLE TO COMMON STOCKHOLDERS	WEIGHTED AVERAGE COMMON SHARES OUTSTANDING	NET EARNINGS PER SHARE
	(IN MILLIONS)		
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
Year Ended December 31, 2000:			
Basic earnings per share	$ 720	127	$ 5.66
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 $3)	5	3	
Potential common shares issuable upon the exercise of outstanding stock options	--	2	
Diluted earnings per share	$ 725	132	$ 5.50

The senior convertible debentures included in the 2000 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.

	2002	2001	2000
Options excluded from dilution calculation (in millions)	5	3	1
Range of exercise prices	$45.49 - $89.66	$48.13 - $89.66	$55.54 - $89.66
Weighted average exercise price	$50.85	$56.11	$66.64

The excluded options for 2002 expire between January 24, 2003 and December 2, 2012.

Comprehensive Earnings or Loss

Devon's comprehensive earnings or loss information is included in the accompanying consolidated statements of stockholders' equity. A summary of accumulated other comprehensive earnings or loss as of December 31, 2002, 2001 and 2000, 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, 1999	$ (28)	--	(1)	(36)	(65)
2000 activity	(10)	--	1	(18)	(27)
Deferred taxes	--	--	--	7	7
2000 activity, net of deferred taxes	(10)	--	1	(11)	(20)
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)

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.

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 accumulated other comprehensive loss.

Dividends

Dividends on Devon's common stock were paid in 2002, 2001 and 2000 at a per share rate of $0.05 per quarter. As adjusted for the pooling-of-interests method of accounting followed for the 2000 Santa Fe Snyder merger, annual dividends per share for 2002, 2001 and 2000 were $0.20, $0.20 and $0.17, respectively.

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 11 for a discussion of amounts recorded for these liabilities.

Impact of Recently Issued Accounting Standards Not Yet Adopted

In June 2001, the FASB issued SFAS No. 143, Accounting for Asset Retirement Obligations. 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 for settlement. The initial measurement of the asset retirement obligation is to be the discounted present fair value, defined as "the price that an entity would have to pay a willing third party of comparable credit standing to assume the liability in a current transaction other than in a forced or liquidation sale."

The asset retirement cost equal to the discounted fair value of the retirement obligation is to be capitalized as part of the cost of the related long-lived asset and allocated to expense using a systematic and rational method.

Devon will adopt SFAS No. 143 effective January 1, 2003 using a cumulative effect approach to recognize transition amounts for asset retirement obligations, asset retirement costs and accumulated depreciation.

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 of SFAS No. 143 on January 1, 2003, Devon expects to record a cumulative-effect-type adjustment for an increase to net earnings of between $10 million and $30 million, net of deferred tax expense of between $5 million and $15 million. Additionally, Devon expects to establish an asset retirement obligation of between $425 million and $475 million, an increase to property and equipment of between $375 million and $425 million and a decrease in accumulated DD&A of between $65 million and $95 million.

The FASB issued Statement No. 145, Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections, on April 30, 2002. SFAS No. 145 will be effective for fiscal years beginning after May 15, 2002. This statement rescinds SFAS No. 4, Reporting Gains and Losses From Extinguishment of Debt, and requires that all gains and losses from extinguishment of debt should be classified as extraordinary items only if they meet the criteria in APB No. 30. Applying APB No. 30 will distinguish transactions that are part of an entity’s recurring operations from those that are unusual or infrequent or that meet the criteria for classification as an extraordinary item. Any gain or loss on extinguishment of debt that was classified as an extraordinary item in prior periods presented that does not meet the criteria in APB No. 30 for classification as an extraordinary item must be reclassified. Devon early adopted the provisions related to SFAS No. 145 during the fourth quarter 2002. With the adoption of SFAS No. 145, a loss of $6 million resulting from extinguishment of debt in 1999 was reclassified from extraordinary loss to interest expense, and 1999’s current income tax expense was reduced by the $2 million tax benefit related to the loss from early extinguishment.

The FASB issued Statement No. 146, Accounting for Costs Associated with Exit or Disposal Activities, in June 2002. SFAS No. 146 addresses financial accounting and reporting for costs associated with exit or disposal activities and nullifies Emerging Issues Task Force Issue No. 94-3, Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs incurred in a Restructuring). SFAS No. 146 applies to costs incurred in an “exit activity” which includes, but is not limited to, a restructuring, or a “disposal activity” covered by SFAS No. 144.

SFAS No. 146 requires that a liability for a cost associated with an exit or disposal activity be recognized when the liability is incurred. Previously, under Issue 94-3, a liability for an exit cost was recognized at the date of an entity’s commitment to an exit plan. Statement No. 146 also establishes that fair value is the objective for initial measurement of the liability.

The provisions of SFAS No. 146 are effective for exit or disposal activities that are initiated after December 31, 2002. Devon currently has no such exit or disposal activities planned.

In November 2002, the FASB issued Interpretation No. 45, Guarantor’s Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness to Others, an interpretation of FASB Statements No. 5, 57 and 107 and a rescission of FASB Interpretation No. 34. This Interpretation elaborates on the disclosures to be made by a guarantor in its interim and annual financial statements about its obligations under guarantees issued. The Interpretation also clarifies that a guarantor is required to recognize, at inception of a guarantee, a liability for the fair value of the obligation undertaken. The initial recognition and measurement provisions of the Interpretation are applicable to guarantees issued or modified after December 31, 2002 and are not expected to have a material effect on Devon’s financial statements. The disclosure requirements are effective for financial statements of interim and annual periods ending after December 31, 2002.

In December 2002, the FASB issued SFAS No. 148, Accounting for Stock-Based Compensation – Transition and Disclosure, an amendment of FASB Statement No. 123. This Statement amends FASB Statement No. 123, Accounting for Stock-Based Compensation, to provide alternative methods of transition for a voluntary change to the fair value method of accounting for stock-based employee compensation. In addition, this Statement amends the disclosure requirements of Statement No. 123 to require prominent disclosures in both annual and interim financial statements. Certain of the disclosure modifications are required for fiscal years ending after December 15, 2002 and are included in the notes to these consolidated financial statements.

In January 2003, the FASB issued Interpretation No. 46, Consolidation of Variable Interest Entities, an Interpretation of Accounting Research Bulletin No. 51. Interpretation No. 46 requires a company to consolidate a variable interest entity if the company has a variable interest (or combination of variable interests) that will absorb a majority of the entity’s expected losses if they occur, receive a majority of the entity’s expected residual returns if they occur, or both. A direct or indirect ability to make decisions that significantly affect the results of the activities of a variable interest entity is a strong indication that a company has one or both of the characteristics that would require consolidation of the variable interest entity. Interpretation No. 46 also requires additional disclosures regarding variable interest entities. The new interpretation is effective immediately for variable interest entities created after January 31, 2003, and is effective in the first interim or annual period beginning after June 15, 2003, for variable interest entities in which a company holds a variable interest that it acquired before February 1, 2003. Devon owns no interests in variable interest entities, and therefore this new interpretation will not affect Devon’s consolidated financial statements.

Reclassification

Certain of the 2001 and 2000 amounts in the accompanying consolidated financial statements have been reclassified to conform to the 2002 presentation.

2. Business Combinations and Pro Forma Information

Mitchell Energy & Development Corp. Merger

On January 24, 2002, Devon completed its acquisition of 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 6).

Devon acquired Mitchell 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 acquisition 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		128
Deferred income taxes		796
Total purchase price plus liabilities assumed	$	4,816
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)		1,355
Total fair value of assets acquired	$	4,816

Anderson Exploration Ltd. Acquisition

On October 15, 2001, Devon accepted all of the Anderson common shares tendered by Anderson stockholders in the tender offer, which represented approximately 97% of the outstanding Anderson common shares. On October 17, 2001, Devon completed its acquisition of Anderson by a compulsory acquisition under the Canada Business Corporations Act of the remaining 3% of Anderson common shares. The cost to Devon of acquiring Anderson’s outstanding common shares and paying for the intrinsic value of Anderson’s outstanding options and appreciation rights was approximately $3.5 billion, which was funded from the sale of $3 billion of debt securities and borrowings under the $3.0 billion senior unsecured term loan credit facility (see Note 6).

Devon acquired Anderson to increase the scope of its Canadian operations, for the exposure to north Canada’s exploratory areas and to increase exposure to the North American natural gas market.

The calculation of the purchase price and the allocation to assets and liabilities as of October 15, 2001, are shown below.

		(IN MILLIONS, EXCEPT SHARE PRICE)
Calculation and allocation of purchase price:		
Number of Anderson common shares outstanding		132
Acquisition price per share	$	25.68
Cash paid to Anderson stockholders	$	3,386
Cash paid to settle Anderson employees' stock options and appreciation rights		92
		3,478
Plus estimated acquisition costs incurred		35
Total purchase price		3,513
Plus fair value of liabilities assumed by Devon:		
Current liabilities		251
Long-term debt		1,017
Other long-term liabilities		3
Fair value of financial instruments		30
Deferred income taxes		1,407
Total purchase price plus liabilities assumed	$	6,221
Fair value of assets acquired by Devon:		
Current assets		214
Proved oil and gas properties		2,605
Unproved oil and gas properties		1,432
Other property and equipment		21
Goodwill (none deductible for income tax purposes)		1,949
Total fair value of assets acquired	$	6,221

Pro Forma Information

Set forth in the following table is certain unaudited pro forma financial information for the years ended December 31, 2002 and 2001. The information has been prepared assuming the Anderson acquisition and the Mitchell merger were consummated on January 1, 2001. 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, 2001. The pro forma information also should not be used as an indication of the future results that Devon will achieve after the transactions.

The following should be considered in connection with the pro forma financial information presented:

- On February 12, 2001, Anderson acquired all of the outstanding shares of Numac Energy Inc. The summary unaudited pro forma combined statements of operations do not include any results from Numac's operations prior to February 12, 2001.

- Devon's historical results of operations for the year ended December 31, 2001 include $34 million of amortization expense for goodwill related to previous mergers. As of January 1, 2002, in accordance with new accounting pronouncements, such goodwill is no longer amortized, but instead is tested for impairment at least annually. No goodwill amortization expense has been recognized in the pro forma statements of operations for the goodwill related to the Anderson acquisition or the Mitchell merger.

	PRO FORMA INFORMATION YEAR ENDED DECEMBER 31, 2002	2001
	(IN MILLIONS, EXCEPT PER SHARE AMOUNTS AND PRODUCTION VOLUMES) (UNAUDITED)	
Revenues		
Oil sales	$ 911	1,059
Gas sales	2,155	3,133
Natural gas liquids sales	280	306
Marketing and midstream revenues	1,069	1,238
Total revenues	4,415	5,736
Operating Costs and Expenses		
Lease operating expenses	625	705
Transportation costs	157	155
Production taxes	112	148
Marketing and midstream operating costs and expenses	873	1,085
Depreciation, depletion and amortization of property and equipment	1,230	1,358
Amortization of goodwill	--	34
General and administrative expenses	224	205
Expenses related to mergers	--	1
Reduction of carrying value of oil and gas properties	651	1,136
Total operating costs and expenses	3,872	4,827
Earnings from operations	543	909
Other Income (Expenses)		
Interest expense	(534)	(507)
Effects of changes in foreign currency exchange rates	1	(19)
Change in fair value of financial instruments	28	(15)
Impairment of ChevronTexaco Corporation common stock	(205)	--
Other income	34	68
Net other expenses	(676)	(473)
Earnings (loss) from continuing operations before income tax expense (benefit) and cumulative effect of change in accounting principle	(133)	436
Income Tax Expense (Benefit)		
Current	23	55
Deferred	(215)	96
Total income tax expense (benefit)	(192)	151
Earnings from continuing operations before cumulative effect of change in accounting principle	59	285
Discontinued Operations		
Results of discontinued operations before income taxes (including net gain on disposal of $31 million in 2002)	54	56
Total income tax expense	9	25
Net results of discontinued operations	45	31
Earnings before cumulative effect of change in accounting principle	104	316
Cumulative effect of change in accounting principle	--	49
Net earnings	104	365
Preferred stock dividends	10	10
Net earnings applicable to common stockholders	$ 94	355

	PRO FORMA INFORMATION YEAR ENDED DECEMBER 31, (IN MILLIONS, EXCEPT PER SHARE AMOUNTS AND PRODUCTION VOLUMES) 2002	2001
Basic earnings per average common share outstanding:		
Earnings from continuing operations	$ 0.31	1.75
Net results of discontinued operations	0.29	0.21
Cumulative effect of change in accounting principle	--	0.31
Net earnings	$ 0.60	2.27
Diluted earnings per average common share outstanding:		
Earnings from continuing operations	0.31	1.73
Net results of discontinued operations	0.29	0.20
Cumulative effect of change in accounting principle	--	0.30
Net earnings	$ 0.60	2.23
Weighted average common shares outstanding - basic	157	157
Weighted average common shares outstanding - diluted	158	164
Production volumes:		
Oil (MMBbls)	42	50
Gas (Bcf)	771	802
NGLs (MMBbls)	20	17
MMBoe	191	201

Santa Fe Snyder Merger

Devon closed its merger with Santa Fe Snyder Corporation ("Santa Fe Snyder") on August 29, 2000. The merger was accounted for using the pooling-of-interests method of accounting for business combinations. Accordingly, all operational and financial information contained herein includes the combined amounts for Devon and Santa Fe Snyder for all periods presented.

Devon issued approximately 41 million shares of its common stock to the former stockholders of Santa Fe Snyder based on an exchange ratio of 0.22 shares of Devon common stock for each share of Santa Fe Snyder common stock. Because the merger was accounted for using the pooling-of-interests method, all combined share information has been retroactively restated to reflect the exchange ratio.

During 2000, Devon recorded a pre-tax charge of $60 million ($37 million net of tax) for direct costs related to the Santa Fe Snyder merger.

3. Supplemental Cash Flow Information

Cash payments (refunds) for interest and income taxes in 2002, 2001 and 2000 are presented below:

	YEAR ENDED DECEMBER 31, 2002	2001 (IN MILLIONS)	2000
Interest paid	$ 248	118	155
Income taxes paid (refunded)	$ (12)	185	80

The 2002 Mitchell acquisition and the 2001 Anderson acquisition involved non-cash consideration as presented below:

	2002 (IN MILLIONS)	2001
Value of common stock issued	$ 1,512	--
Employee stock options assumed	27	--
Liabilities assumed	824	1,301
Deferred tax liability created	796	1,407
Fair value of assets acquired with non-cash consideration	$ 3,159	2,708

4. Accounts Receivable

The components of accounts receivable included the following:

		December 31,		
		2002	2001	2000
			(IN MILLIONS)	
Oil, gas and natural gas liquids revenue accruals	$	422	275	402
Joint interest billings		102	145	123
Marketing and midstream revenues		73	1	--
Other		52	72	41
		649	493	566
Allowance for doubtful accounts		(10)	(4)	(4)
Net accounts receivable	$	639	489	562

5. Property And Equipment

Property and equipment included the following:

		December 31,		
		2002	2001	2000
			(IN MILLIONS)	
Oil and gas properties:				
Subject to amortization	$	15,020	12,580	8,555
Not subject to amortization:				
Acquired in 2002		730	--	--
Acquired in 2001		1,338	1,638	--
Acquired in 2000		52	65	74
Acquired prior to 2000		169	226	240
Accumulated depreciation, depletion and amortization		(7,796)	(6,048)	(4,382)
Net oil and gas properties		9,513	8,461	4,487
Other property and equipment		1,477	390	222
Accumulated depreciation and amortization		(138)	(89)	(47)
Net other property and equipment		1,339	301	175
Property and equipment, net of accumulated depreciation, depletion and amortization	$	10,852	8,762	4,662

The costs not subject to amortization relate to unproved properties that 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,		
		2002	2001	2000
			(IN MILLIONS)	
Depreciation, depletion and amortization of oil and gas properties	$	1,106	793	632
Depreciation and amortization of other property and equipment		97	30	23
Amortization of other assets		8	8	7
Total	$	1,211	831	662

6. Long-Term Debt and Related Expenses

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

	DECEMBER 31, 2002	2001	2000
		(IN MILLIONS)	
Borrowings under credit facilities with banks	$ --	50	147
Commercial paper borrowings	--	75	--
$3 billion term loan credit facility	1,135	1,046	--
Debentures exchangeable into shares of ChevronTexaco Corporation common stock:			
4.90% due August 15, 2008	444	444	444
4.95% due August 15, 2008	316	316	316
Discount on exchangeable debentures	(98)	(111)	--
Zero coupon convertible senior debentures exchangeable into shares of Devon Energy Corp. common stock, 3.875% due June 27, 2020	388	374	360
Other debentures and notes:			
6.75% due February 15, 2004	211	--	--
8.05% due June 15, 2004	125	125	125
7.25% due July 18, 2005	111	110	--
7.42% due October 1, 2005	--	23	--
7.57% due October 4, 2005	--	31	--
10.25% due November 1, 2005	236	236	250
6.55% due August 2, 2006	127	126	--
8.75% due June 15, 2007	--	175	175
10.125% due November 15, 2009	177	177	200
6.75% due March 15, 2011	400	400	--
6.875% due September 30, 2011	1,750	1,750	--
7.875% due September 30, 2031	1,250	1,250	--
7.95% due April 15, 2032	1,000	--	--
Fair value adjustment on 8.05% notes related to interest rate swap	5	--	--
Net (discount) premium on other debentures and notes	(15)	(8)	32
	7,562	6,589	2,049
Less amount classified as current	--	--	--
Long-term debt	$ 7,562	6,589	2,049

Maturities of long-term debt as of December 31, 2002, excluding the $113 million of discounts net of premiums and the $5 million fair value adjustment, are as follows (in millions):

2003	$ --
2004	336
2005	347
2006	1,262
2007	--
2008 and thereafter	5,725
Total	$ 7,670

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. On June 7, 2002, Devon renewed the $525 million Tranche B facility and its $275 million Canadian Facility.

The Tranche A facility matures on October 15, 2004. Devon may borrow funds under the Tranche B facility until June 5, 2003 (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 6, 2003, at the end of the Tranche B Revolving Period, Devon may convert the then outstanding balance under the Tranche B facility to a two-year term loan by paying the Agent a fee of 12.5 basis points. The applicable borrowing rate would be at LIBOR plus 125 basis points. On December 31, 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, 2002, net of $25 million of outstanding letters of credit, was $700 million.

Devon may borrow funds under the $275 million Canadian Facility until June 5, 2003 (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, 2002, there were no borrowings under the $275 million Canadian Facility.

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. The weighted average interest rate on the $50 million and $147 million outstanding under the previous facilities at December 31, 2001 and 2000, was 4.8% and 6.1%, respectively.

The agreements governing the Credit Facilities contain certain covenants and restrictions, including a maximum debt-to-capitalization ratio. At December 31, 2002, Devon was in compliance with such covenants and restrictions.

Letter of Credit Facility

On July 25, 2002, Devon renewed and increased its letter of credit and revolving bank facility ("LOC Facility") for its Canadian operations. This C$150 million LOC Facility will be used primarily by Devon's wholly-owned subsidiaries, Devon Canada Corporation and Northstar Energy Corporation, to issue letters of credit. As of December 31, 2002, C$109 million ($69 million converted to U.S. dollars using the December 31, 2002, exchange rate) of letters of credit were issued under the LOC Facility primarily for Canadian drilling commitments.

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, 2002, Devon had no commercial paper debt outstanding. As of December 31, 2001, Devon had $75 million of borrowings under its commercial paper program at an average rate of 3.5%. Because Devon had the intent and ability to refinance the balance due with borrowings under its U.S. Facility, the $75 million outstanding under the commercial paper program was classified as long-term debt on the December 31, 2001, consolidated balance sheet.

$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. Devon and Devon Financing may borrow funds under this facility subject to conditions usual in commercial transactions of this nature, including the absence of any default under this facility. 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. Through June 17, 2002, this margin was fixed at 100 basis points. Thereafter, the margin is based on Devon's debt rating. Based on Devon's current debt rating, the margin after June 17, 2002, is 100 basis points. As of December 31, 2002, the average interest rate on this facility was 2.5%.

Prior to December 31, 2001, Devon borrowed $1 billion under this term loan credit facility to partially fund the Anderson acquisition. The remaining $2 billion of availability was utilized upon the closing of the Mitchell acquisition on January 24, 2002. As of December 31, 2002, $1.9 billion of the original $3 billion balance had been retired. The primary sources of the repayments were the issuance of $1 billion of debt securities, of which $0.8 billion was used to pay down debt, and $1.4 billion from the sale of certain oil and gas properties, of which $1.1 billion was used to pay down debt.

The terms of this facility require repayment of the debt during the following periods:

	(IN MILLIONS)
April 15, 2006	$ 335
October 15, 2006	800
Total	$ 1,135

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, 2002, 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% 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, Devon may, at its option, pay to any holder an amount of cash equal to the market value of the ChevronTexaco common stock to satisfy the exchange request. However, at maturity, the holders will receive an amount at least equal to the face value of the debt outstanding. Such amount will either be in cash or in a combination of cash and ChevronTexaco common stock.

As of December 31, 2002, 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 $107-7/32 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. The fair value approximated the face value of the exchangeable debentures. As a result, no premium or discount was recorded on these exchangeable debentures. However, pursuant to the adoption of SFAS No. 133 effective January 1, 2001, these debentures were revalued as of August 17, 1999. Under SFAS No. 133, the total fair value of the debentures was allocated between the interest-bearing debt and the option to exchange ChevronTexaco common stock that is embedded in the debentures. Accordingly, the debt portion of the debentures was reduced by $140 million as of August 17, 1999. This discount is being accreted using the effective interest method, and has raised the effective interest rate on the debentures to 7.76% in 2001 compared to 4.92% prior to 2001.

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

In connection with the Mitchell acquisition, Devon assumed $211 million of 6.75% senior notes due 2004. The fair value of these senior notes approximated the face value. As a result, no premium or discount was recorded on these senior notes.

In June 1999, Devon issued $125 million of 8.05% notes due 2004. The notes were issued 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, which mature June 15, 2004, are redeemable, upon not less than 30 nor more than 60 days notice, as a whole or in part, at the option of Devon. The notes are general unsecured obligations of Devon.

In connection with the Anderson acquisition, Devon assumed $702 million of senior notes. The table below summarizes the debt assumed, 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.

FAIR VALUE OF DEBT ASSUMED	EFFECTIVE RATE OF DEBT ASSUMED	DEBT ASSUMED
	(IN MILLIONS)	
7.25% senior notes due 2005	$ 116	6.3%
7.42% senior notes due 2005	24	5.7%
7.57% senior notes due 2005	33	5.7%
6.55% senior notes due 2006	129	6.5%
6.75% senior notes due 2011	400	6.8%

Devon recorded a $2 million early retirement premium in 2001 related to the early retirement of the above 7.57% and 7.42% senior notes.

The 10.25% and 10.125% debentures were assumed as part of the PennzEnergy merger. 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.

During October 2001, Devon repurchased $14 million and $23 million of its 10.25% debentures and 10.125% debentures, respectively. Devon recorded an early retirement premium of $5 million related to this repurchase.

On October 3, 2001, Devon, through Devon Financing, sold $1.75 billion of 6.875% notes due September 30, 2011 and $1.25 billion of 7.875% debentures due September 30, 2031. The debt securities 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%.

Interest on the debt securities is payable by Devon Financing semi-annually on March 30 and September 30 of each year. The indenture governing the debt securities limits both Devon Financing's and Devon's ability to incur debt secured by liens or enter into mergers or consolidations, or transfer all or substantially all of their respective assets. This is unless the successor company assumes Devon Financing's or Devon's obligations under the indenture.

On March 25, 2002, Devon sold $1 billion of 7.95% notes due April 15, 2032. The net proceeds received, after discounts and issuance costs, were $986 million. The debt securities are unsecured and unsubordinated obligations of Devon. The net proceeds 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 2002, 2001 and 2000:

	YEAR ENDED DECEMBER 31,		
	2002	2001	2000
		(IN MILLIONS)	
Interest based on debt outstanding	$ 499	200	157
Accretion (amortization) of debt discount (premium), net	13	10	(4)
Facility and agency fees	2	1	3
Amortization of capitalized loan costs	8	3	2
Capitalized interest	(4)	(3)	(3)
Early retirement premiums	8	7	--
Other	7	2	--
Total interest expense	$ 533	220	155

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. Until their retirement in mid-January 2000, $225 million of additional notes denominated in U.S. dollars were owed by another Canadian subsidiary. Changes in the exchange rate between the U.S. dollar and the Canadian dollar from the dates the notes were issued or assumed as part of an acquisition to the dates 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 are required to be included in determining net earnings for the period in which the exchange rate changed. The rate of conversion of Canadian dollars to U.S. dollars increased in 2002 and declined in 2001 and 2000. Therefore, $1 million of reduced expense was recorded in 2002 and $11 million and $3 million of increased expense was recorded in 2001 and 2000, respectively.

7. Income Taxes

At December 31, 2002, 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	2008 – 2021	$ 10
Net operating loss – various states	2003 – 2016	$ 119
Net operating loss – Canada	2005 – 2009	$ 119
Net operating loss – International	Indefinite	$ 63
Minimum tax credits	Indefinite	$ 164

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 2002, 2001 and 2000 were as follows:

		YEAR ENDED DECEMBER 31,	
	2002	2001	2000
		(IN MILLIONS)	
Earnings (loss) from continuing operations before income taxes:			
U.S	$ 354	458	872
Canada	(515)	(357)	156
International	27	(73)	10
Total	$ (134)	28	1,038
Current income tax expense (benefit):			
U.S. federal	$ (34)	23	107
Various states	11	6	6
Canada	28	8	2
International	18	11	5
Total current tax expense	23	48	120
Deferred income tax expense (benefit):			
U.S. federal	56	124	152
Various states	(14)	(32)	33
Canada	(253)	(145)	67
International	(5)	10	5
Total deferred tax expense (benefit)	(216)	(43)	257
Total income tax expense (benefit)	$ (193)	5	377

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) before income taxes as a result of the following:

		YEAR ENDED DECEMBER 31,	
	2002	2001	2000
		(IN MILLIONS)	
Expected income tax (benefit) based on U.S. statutory tax rate of 35%	$ (47)	10	363
Benefit from disposition of certain foreign assets	--	--	(46)
Financial expenses not deductible for income tax purposes	--	12	15
Dividends received deduction	(5)	(5)	(5)
Nonconventional fuel source credits	(19)	(19)	(8)
State income taxes	7	4	15
Taxation on foreign operations	(121)	5	22
Other	(8)	(2)	21
Total income tax expense (benefit)	$ (193)	5	377

The tax effects of temporary differences that gave rise to significant portions of the deferred tax assets and liabilities at December 31, 2002, 2001 and 2000 are presented below:

	DECEMBER 31,		
	2002	2001	2000
		(IN MILLIONS)	
Deferred tax assets:			
Net operating loss carryforwards	$ 78	39	123
Minimum tax credit carryforwards	164	118	85
Long-term debt	--	6	17
Fair value of financial instruments	46	7	--
Pension benefit obligation	42	11	--
Other	53	26	95
Total deferred tax assets	383	207	320
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	(2,863)	(2,189)	(694)
ChevronTexaco Corporation common stock	(147)	(213)	(167)
Other	--	(11)	(84)
Total deferred tax liabilities	(3,010)	(2,413)	(945)
Net deferred tax liability	$ (2,627)	(2,206)	(625)

As shown in the above table, Devon has recognized $383 million of deferred tax assets as of December 31, 2002. Such amount consists primarily of $242 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 2008, state net operating loss carryforwards which expire primarily between 2003 and 2016, Canadian carryforwards which expire primarily in 2008, International carryforwards which have no expiration 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 2003 and 2008. 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.

8. Stockholders’ Equity

The authorized capital stock of Devon consists of 400 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 2002, 14 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.

As discussed in Note 2, there were approximately 30 million shares of Devon common stock issued on January 24, 2002, in connection with the Mitchell acquisition. Also, 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, 2002, 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 1988, 1993 and 1997 (the "1988 Plan," the "1993 Plan" and the "1997 Plan"). Options granted under the 1988 Plan and 1993 Plan remain exercisable by the employees owning such options, but no new options will be granted under these plans. At December 31, 2002, there were 13,000 and 309,000 options outstanding under the 1988 Plan and the 1993 Plan, respectively.

On May 21, 1997, Devon's stockholders adopted the 1997 Plan and reserved two million shares of Common Stock for issuance thereunder. On December 9, 1998, Devon's stockholders voted to increase the reserved number of shares to three million. On August 17, 1999, Devon's stockholders voted to increase the reserved number of shares to six million. On August 29, 2000, Devon's stockholders voted to increase the reserved number of shares to 10 million.

The exercise price of stock options granted under the 1997 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 10 years from the date of grant. Under the 1997 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 1997 Plan is administered by a committee comprised of non-management members of the Board of Directors. The 1997 Plan expires on April 25, 2007. As of December 31, 2002, there were 7,477,000 options outstanding under the 1997 Plan. There were 1,237,000 options available for future grants as of December 31, 2002.

In addition to the stock options outstanding under the 1988 Plan, 1993 Plan and 1997 Plan, there were approximately 1,327,000, 774,000, 1,314,000 and 17,000 stock options outstanding at the end of 2002 that were assumed as part of the Mitchell acquisition, the Santa Fe Snyder merger, the PennzEnergy merger and the Northstar combination, respectively.

A summary of the status of Devon's stock option plans as of December 31, 2000, 2001 and 2002, and changes during each of the years then ended, is presented below.

	OPTIONS OUTSTANDING		OPTIONS EXERCISABLE	
	NUMBER OUTSTANDING (IN THOUSANDS)	WEIGHTED AVERAGE EXERCISE PRICE	NUMBER EXERCISABLE (IN THOUSANDS)	WEIGHTED AVERAGE EXERCISE PRICE
Balance at December 31, 1999	8,554	$ 38.20	7,064	$ 39.55
Options granted	1,625	$ 51.43		
Options exercised	(2,489)	$ 33.11		
Options forfeited	(334)	$ 60.35		
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 acquisition	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

The weighted average fair values of options granted during 2002, 2001 and 2000 were $15.25, $13.17 and $28.73, 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 2002, 2001 and 2000, respectively: risk-free interest rates of 3.2%, 3.8% and 5.5%; dividend yields of 0.4%, 0.6% and 0.4%; expected lives of five, five and five years; and volatility of the price of the underlying common stock of 41.8%, 42.2% and 40.0%.

The following table summarizes information about Devon's stock options that were outstanding, and those which were exercisable, as of December 31, 2002:

	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)	
$10.270-$25.667	1,157	2.70 Years	$ 18.63	1,157	$ 18.63
$29.125-$33.381	956	6.12 Years	$ 30.87	956	$ 30.87
$34.375-$39.773	3,281	6.74 Years	$ 35.40	1,735	$ 35.72
$40.483-$49.950	3,566	6.99 Years	$ 46.00	1,244	$ 45.82
$50.142-$59.813	1,772	5.88 Years	$ 53.04	1,404	$ 53.36
$60.150-$89.660	499	4.36 Years	$ 70.79	495	$ 70.87
	11,231	6.11 Years	$ 41.00	6,991	$ 40.05

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 $0.01 per right until the rights become exercisable.

9. Financial Instruments

The following table presents the carrying amounts and estimated fair values of Devon's financial instruments at December 31, 2002, 2001 and 2000.

	2002		2001		2000	
	CARRYING AMOUNT	FAIR VALUE	CARRYING AMOUNT	FAIR VALUE	CARRYING AMOUNT	FAIR VALUE
			(IN MILLIONS)			
Investments	$ 479	479	644	644	606	606
Oil and gas price hedge agreements	$ (144)	(144)	225	225	--	(58)
Interest rate swap agreements	$ (5)	(5)	(9)	(9)	--	--
Electricity hedge agreements	$ (2)	(2)	(12)	(12)	--	--
Foreign exchange hedge agreements	$ (1)	(1)	(4)	(4)	--	(1)
Embedded option in exchangeable debentures	$ (12)	(12)	(34)	(34)	--	--
Long-term debt	$ (7,562)	(8,425)	(6,589)	(6,699)	(2,049)	(2,050)

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, 2002, 2001 and 2000.

Investments – The fair values of investments are primarily 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.

Devon's total hedged positions as of January 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 natural gas production in 2003. These swaps will result in a fixed price of $3.23 per Mcf on 97,148 Mcf per day of domestic production during 2003. Where necessary, the 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.

Costless Price Collars

Devon has also entered into costless price collars that set a floor and ceiling price for a portion of its 2003 and 2004 oil and natural gas production. The following tables include information on these collars. The floor and ceiling prices related to domestic oil production are based on NYMEX. The NYMEX price is the monthly average of settled prices on each trading day for West Texas Intermediate Crude oil delivered at Cushing, Oklahoma. The gas prices shown in the following table have been adjusted to a NYMEX-based price, using Devon's estimates of 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.

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 oil or 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 content of gas production, 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.

The floor and ceiling prices in the following tables are weighted averages of all the various collars.

OIL PRODUCTION

		WEIGHTED AVERAGE	
YEAR	BBLS/DAY	FLOOR PRICE PER BBL	CEILING PRICE PER BBL
2003	53,537	$ 22.26	$ 28.14
2004	4,000	$ 20.00	$ 27.00

GAS PRODUCTION

		WEIGHTED AVERAGE	
YEAR	MMBTU/DAY	FLOOR PRICE PER MMBTU	CEILING PRICE PER MMBTU
2003	655,096	$ 3.34	$ 5.11
2004	130,000	$ 3.47	$ 6.44

Interest Rate Swaps

Devon assumed certain interest rate swaps as a result of the Anderson acquisition. Under these interest rate swaps, Devon has swapped a floating rate for a fixed rate. Under such swaps, Devon will record a fixed rate of 6.3% on $98 million of debt in 2003, 6.4% on $79 million of debt in 2004 through 2006 and 6.3% on $24 million of debt in 2007. The amount of gains or losses realized from such swaps are included as increases or decreases to interest expense.

Devon has also entered into an interest rate swap on its $125 million 8.05% senior notes due in 2004 to swap a fixed interest rate for a variable interest rate. The variable interest rate on this instrument is based on LIBOR plus a margin of 336 basis points.

Foreign Currency Exchange Rate Swaps

Devon assumed certain foreign currency exchange rate swaps in the Anderson acquisition. These swaps require Devon to sell $12 million at average Canadian-to-U.S. exchange rates of $0.676, and buy the same amount of dollars at the floating exchange rate, in 2003.

10. Retirement Plans

Devon has non-contributory defined benefit retirement plans (the "Basic Plans") that include U.S. and Canadian employees meeting certain age and service requirements. The benefits are based on the employee's years of service and compensation. During 2002, Devon established a funding policy regarding the Basic Plans such that it would contribute the amount of funds necessary so that the Basic Plans' assets would be equal to the related accumulated benefit obligation by the end of 2004. As of December 31, 2002, the Basic Plans' accumulated benefit obligation totaled $363 million, which was $82 million more than the related assets. Devon's intentions are to fund this deficit over the two-year period ending December 31, 2004. The actual amount of contributions required during this period will depend on investment returns from the plan assets during the same period.

Devon also has separate defined benefit retirement plans (the "Supplementary Plans") which are non-contributory and include only certain employees whose benefits under the Basic Plans are limited by income tax regulations. The Supplementary Plans' benefits are based on the employee's years of service and compensation. Devon's funding policy for the Supplementary Plans is to fund the benefits as they become payable. Rights to amend or terminate the Supplementary Plans are retained by Devon.

Devon has defined benefit postretirement plans, which are unfunded, and cover substantially all employees. The plans provide medical and, in some cases, life insurance benefits and are, depending on the type of plan, either contributory or non-contributory. The accounting for the health care plan anticipates future cost-sharing changes that are consistent with Devon's expressed intent to increase, where possible, contributions from future retirees.

The following table sets forth the plans' benefit obligations, plan assets, reconciliation of funded status, amounts recognized in the consolidated balance sheets and the actuarial assumptions used as of December 31, 2002, 2001 and 2000.

	PENSION BENEFITS			OTHER POSTRETIREMENT BENEFITS		
	2002	2001	2000	2002	2001	2000
			(IN MILLIONS)			
Change in benefit obligation:						
Benefit obligation at beginning of year	$ 210	165	156	$ 33	32	38
Service cost	9	5	7	1	--	1
Interest cost	28	13	11	4	2	2
Participant contributions	--	--	--	1	1	--
Amendments	--	5	4	--	(1)	(2)
Mergers and acquisitions	208	16	--	30	--	--
Special termination benefits	--	3	--	--	--	--
Settlement payments	(15)	(4)	--	--	--	--
Curtailment loss (gain)	2	(1)	(3)	--	--	--
Actuarial loss (gain)	42	17	(3)	6	4	(3)
Benefits paid	(24)	(9)	(7)	(7)	(5)	(4)
Benefit obligation at end of year	460	210	165	68	33	32
Change in plan assets:						
Fair value of plan assets at beginning of year	156	155	158	--	--	--
Actual return on plan assets	(47)	(9)	3	--	--	--
Mergers and acquisitions	145	17	--	--	--	--
Employer contributions	66	6	1	6	4	4
Participant contributions	--	--	--	1	1	--
Settlement payments	(15)	(4)	--	--	--	--
Administrative expenses	--	--	--	--	--	--
Benefits paid	(24)	(9)	(7)	(7)	(5)	(4)
Fair value of plan assets at end of year	281	156	155	--	--	--
Funded status	(179)	(54)	(10)	(68)	(33)	(32)
Unrecognized net actuarial (gain) loss	152	35	10	8	2	(2)
Unrecognized prior service cost	5	6	1	(1)	(1)	(1)
Unrecognized net transition (asset) obligation	--	--	(6)	--	--	1
Net amount recognized	$ (22)	(13)	(5)	$ (61)	(32)	(34)
The net amounts recognized in the consolidated balance sheets consist of:						
(Accrued) prepaid benefit cost	$ (22)	(13)	(5)	$ (61)	(32)	(34)
Additional minimum liability	(118)	(33)	(1)	--	--	--
Intangible asset	5	5	1	--	--	--
Accumulated other comprehensive loss	113	28	--	--	--	--
Net amount recognized	$ (22)	(13)	(5)	$ (61)	(32)	(34)
Assumptions:						
Discount rate	6.72%	7.10%	7.65%	6.75%	7.15%	7.65%
Expected return on plan assets	8.27%	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%

As indicated in the prior table, Devon's defined benefit plans had a combined underfunded status of $179 million as of December 31, 2002. Of this $179 million total, $75 million is attributable to the Supplementary Plans that have no plan assets. However, certain trusts have been established to assist Devon in funding the benefit obligations of such Supplementary Plans. At December 31, 2002, these trusts had investments with a market value of approximately $53 million. This total is included in noncurrent other assets in the accompanying consolidated balance sheets.

The accumulated benefit obligation was in excess of plan assets for each of the defined benefit pension plans as of December 31, 2002.

Net periodic benefit cost included the following components:

	PENSION BENEFITS			OTHER POSTRETIREMENT BENEFITS		
	2002	2001	2000	2002	2001	2000
	(IN MILLIONS)					
Service cost	$ 9	5	7	$ 1	--	1
Interest cost	28	13	11	4	2	2
Expected return on plan assets	(24)	(13)	(13)	--	--	--
Amortization of prior service cost	1	1	--	--	--	--
Recognized net actuarial (gain) loss	2	1	--	--	--	--
Net periodic benefit cost	$ 16	7	5	$ 5	2	3

For measurement purposes, a 10% annual rate of increase in the per capita cost of covered health care benefits was assumed in 2002. The rate was assumed to decrease on a pro-rata basis annually to 5% in the year 2008 and remain at that level thereafter. Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plan. A one percentage-point change in assumed health care cost trend rates would have the following effects:

	ONE-PERCENTAGE POINT DECREASE	ONE-PERCENTAGE POINT INCREASE
	(IN MILLIONS)	
Effect on total of service and interest cost components for 2002	$ --	$ --
Effect on year-end 2002 postretirement benefit obligation	$ 3	$ (4)

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 that are accounted for under SFAS No. 112, Employer's Accounting for Postemployment Benefits. The accrued postemployment benefit liability was approximately $6 million, $7 million and $13 million at the end of 2002, 2001 and 2000, respectively.

Devon has a 401(k) Incentive Savings Plan that 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 $8 million, $5 million and $5 million for the years ended December 31, 2002, 2001 and 2000, respectively.

Devon has defined contribution 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 the years 2002, 2001 and 2000, Devon's combined contributions to the Canadian defined contribution plan and the Canadian savings plan were $8 million, $3 million and $2 million, respectively.

11. 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 in excess of recorded accruals.

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, 2002, Devon's consolidated balance sheet included $8 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 minimus 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 filed by private litigants 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 various suits have been consolidated by the United States Judicial Panel on Multidistrict Litigation for pre-trial proceedings in the matter of In re Natural Gas Royalties Qui Tam Litigation, MDL-1293, United States District Court for the District of Wyoming. Devon believes that it has acted reasonably, has legitimate and strong defenses to all allegations in the suits, and has paid royalties in good faith. Devon does not currently believe that it is subject to material exposure in association with these lawsuits and no liability has been recorded in connection therewith.

Also, pending in federal court in Texas is a similar suit alleging underpaid royalties to the United States in connection with natural gas and natural gas liquids produced and sold from United States owned and/or controlled lands. The claims were filed by private litigants against Devon and numerous other producers, under the federal False Claims Act. The United States served notice of its intent to intervene as to certain defendants, but not Devon. Devon and certain other defendants are challenging the constitutionality of whether a claim under the federal False Claims Act can be maintained absent government intervention. Devon believes that it has acted reasonably and paid royalties in good faith. Devon does not currently believe that it is subject to material exposure in association with this litigation. As a result, Devon's monetary exposure in this suit is not expected to be material.

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.

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

The following is a schedule by year of future minimum rental payments required under operating leases that have initial or remaining noncancelable lease terms in excess of one year as of December 31, 2002:

YEAR ENDING DECEMBER 31,	(IN MILLIONS)
2003	$ 30
2004	33
2005	28
2006	24
2007	20
Thereafter	86
Total minimum lease payments required	$ 221

Total rental expense for all operating leases is as follows for the years ended December 31:

	(IN MILLIONS)	
2002	$	37
2001	$	17
2000	$	19

The 2002 rent expense includes $13 million for the abandonment of certain office space obtained in the Santa Fe Snyder merger.

12. 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, 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, is compared to the ceiling on a quarterly and annual basis. Any excess of the net book value, less related deferred taxes, 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.

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

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

The 2002 Canadian reduction was primarily the result of lower prices. Under the purchase method of accounting for business combinations, acquired oil and gas properties are recorded at fair value as of the date of purchase. Devon estimates such fair value using its estimates of future oil and gas 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 is not necessarily indicative of the fair value of the reserves. 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.

The provisions of SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets, which Devon was required to adopt effective January 1, 2002, are only required to be applied prospectively. As a result, these impairment charges have not been reclassified as part of the Discontinued Operations on the consolidated statements of operations.

13. 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 14.

Following is certain financial information regarding Devon's segments for 2002, 2001 and 2000. The revenues reported are all from external customers.

	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, net of amortization	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
Long-term debt	3,545	4,017	--	7,562
Deferred tax liabilities	1,520	1,062	45	2,627
Other liabilities	333	7	1	341
Stockholders' equity	3,705	385	563	4,653
Total liabilities and stockholders' equity	$ 9,729	5,815	681	16,225
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)		
As Of December 31, 2001:					
Current assets	$	661	192	501	1,354
Property and equipment, net of accumulated depreciation, depletion and amortization		4,051	4,248	463	8,762
Goodwill, net of amortization		209	1,928	69	2,206
Other assets		826	33	3	862
Total assets	$	5,747	6,401	1,036	13,184
Current liabilities		407	367	145	919
Long-term debt		1,987	4,602	--	6,589
Deferred tax liabilities		775	1,316	58	2,149
Other liabilities		224	20	24	268
Stockholders' equity		2,354	96	809	3,259
Total liabilities and stockholders' equity	$	5,747	6,401	1,036	13,184
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

	U.S.	CANADA	INTERNATIONAL	TOTAL
		(IN MILLIONS)		
As Of December 31, 2000:				
Current assets	$ 645	79	104	828
Property and equipment, net of accumulated depreciation, depletion and amortization	3,640	586	436	4,662
Goodwill, net of amortization	244	--	45	289
Assets of discontinued operations	--	--	361	361
Other assets	720	--	--	720
Total assets	$ 5,249	665	946	6,860
Current liabilities	449	74	54	577
Long-term debt	1,902	147	--	2,049
Deferred tax liabilities	537	69	28	634
Liabilities of discontinued operations	--	--	51	51
Other liabilities	259	1	12	272
Stockholders' equity	2,102	374	801	3,277
Total liabilities and stockholders' equity	$ 5,249	665	946	6,860
Year Ended December 31, 2000:				
Revenues				
Oil sales	$ 727	116	63	906
Gas sales	1,305	169	--	1,474
Natural gas liquids sales	136	18	--	154
Marketing and midstream revenues	47	6	--	53
Total revenues	2,215	309	63	2,587
Operating Costs And Expenses				
Lease operating expenses	319	52	17	388
Transportation costs	42	11	--	53
Production taxes	102	1	--	103
Marketing and midstream operating costs and expenses	25	3	--	28
Depreciation, depletion and amortization of property and equipment	565	65	32	662
Amortization of goodwill	41	--	--	41
General and administrative expenses	81	10	5	96
Expenses related to mergers	60	--	--	60
Total operating costs and expenses	1,235	142	54	1,431
Earnings from operations	980	167	9	1,156
Other Income (Expenses)				
Interest expense	(144)	(10)	(1)	(155)
Effects of changes in foreign currency exchange rates	--	(3)	--	(3)
Other income	36	2	2	40
Net other income (expenses)	(108)	(11)	1	(118)
Earnings from continuing operations before income taxes	872	156	10	1,038
Income Tax Expense				
Current	113	2	5	120
Deferred	185	67	5	257
Total income tax expense	298	69	10	377
Earnings from continuing operations	574	87	--	661
Discontinued Operations				
Results of discontinued operations before income taxes	--	--	104	104
Income tax expense	--	--	35	35
Net results of discontinued operations	--	--	69	69
Net earnings	$ 574	87	69	730
Capital expenditures	$ 893	203	52	1,148

14. 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,		
		2002	2001	2000
		(IN MILLIONS)		
Property acquisition costs:				
Proved, excluding deferred income taxes	$	1,538	2,971	247
Deferred income taxes		--	84	--
Total proved, including deferred income taxes	$	1,538	3,055	247
Unproved, excluding deferred income taxes:				
Business combinations		639	1,433	--
Other acquisitions		64	183	54
Deferred income taxes		--	27	--
Total unproved, including deferred income taxes	$	703	1,643	54
Exploration costs	$	383	337	197
Development costs	$	1,140	916	562

		DOMESTIC		
		YEAR ENDED DECEMBER 31,		
		2002	2001	2000
		(IN MILLIONS)		
Property acquisition costs:				
Proved, excluding deferred income taxes	$	1,536	292	177
Deferred income taxes		--	79	--
Total proved, including deferred income taxes	$	1,536	371	177
Unproved, excluding deferred income taxes:				
Business combinations		639	--	--
Other acquisitions		27	158	35
Deferred income taxes		--	27	--
Total unproved, including deferred income taxes	$	666	185	35
Exploration costs	$	161	166	117
Development costs	$	808	726	466

		CANADA		
		YEAR ENDED DECEMBER 31,		
		2002	2001	2000
		(IN MILLIONS)		
Property acquisition costs:				
Proved, excluding deferred income taxes	$	2	2,621	70
Deferred income taxes		--	5	--
Total proved, including deferred income taxes	$	2	2,626	70
Unproved, excluding deferred income taxes:				
Business combinations		--	1,433	--
Other acquisitions		28	24	17
Deferred income taxes		--	--	--
Total unproved, including deferred income taxes	$	28	1,457	17
Exploration costs	$	207	126	55
Development costs	$	299	168	57

		INTERNATIONAL YEAR ENDED DECEMBER 31,		
		2002	2001	2000
		(IN MILLIONS)		
Property acquisition costs:				
Proved, excluding deferred income taxes	$	--	58	--
Deferred income taxes		--	--	--
Total proved, including deferred income taxes	$	--	58	--
Unproved, excluding deferred income taxes:				
Business combinations		--	--	--
Other acquisitions		9	1	2
Deferred income taxes		--	--	--
Total unproved, including deferred income taxes	$	9	1	2
Exploration costs	$	15	45	25
Development costs	$	33	22	39

The preceding Total and International cost incurred tables exclude $16 million, $85 million and $135 million in 2002, 2001 and 2000, respectively, related to discontinued operations.

Pursuant to the full cost method of accounting, Devon capitalizes certain of its general and administrative expenses that are related to property acquisition, exploration and development activities. Such capitalized expenses, which are included in the costs shown in the preceding tables, were $97 million, $77 million and $62 million in the years 2002, 2001 and 2000, 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,		
		2002	2001	2000
		(IN MILLIONS, EXCEPT PER EQUIVALENT BARREL AMOUNTS)		
Oil, gas and natural gas liquids sales	$	3,317	2,793	2,534
Production and operating expenses		(886)	(666)	(544)
Depreciation, depletion and amortization		(1,106)	(793)	(632)
Amortization of goodwill		--	(34)	(41)
General and administrative expenses directly related to oil and gas producing activities		(29)	(17)	(14)
Reduction of carrying value of oil and gas properties		(651)	(979)	--
Income tax expense		(234)	(126)	(533)
Results of operations for oil and gas producing activities	$	411	178	770
Depreciation, depletion and amortization per equivalent barrel of production	$	5.88	6.30	5.58

		DOMESTIC YEAR ENDED DECEMBER 31,		
		2002	2001	2000
		(IN MILLIONS, EXCEPT PER EQUIVALENT BARREL AMOUNTS)		
Oil, gas and natural gas liquids sales	$	2,119	2,260	2,168
Production and operating expenses		(557)	(512)	(463)
Depreciation, depletion and amortization		(737)	(615)	(541)
Amortization of goodwill		--	(34)	(41)
General and administrative expenses directly related to oil and gas producing activities		(14)	(9)	(10)
Reduction of carrying value of oil and gas properties		--	(449)	--
Income tax (expense) benefit		(295)	(263)	(442)
Results of operations for oil and gas producing activities	$	516	378	671
Depreciation, depletion and amortization per equivalent barrel of production	$	6.22	6.48	5.73

		CANADA		
		YEAR ENDED DECEMBER 31,		
		2002	2001	2000
		(IN MILLIONS, EXCEPT PER EQUIVALENT BARREL AMOUNTS)		
Oil, gas and natural gas liquids sales	$	1,144	481	303
Production and operating expenses		(317)	(137)	(64)
Depreciation, depletion and amortization		(364)	(164)	(64)
General and administrative expenses directly related to oil and gas producing activities		(14)	(6)	(3)
Reduction of carrying value of oil and gas properties		(651)	(434)	--
Income tax benefit (expense)		74	102	(79)
Results of operations for oil and gas producing activities	$	(128)	(158)	93
Depreciation, depletion and amortization per equivalent barrel of production	$	5.39	5.74	4.05

		INTERNATIONAL		
		YEAR ENDED DECEMBER 31,		
		2002	2001	2000
		(IN MILLIONS, EXCEPT PER EQUIVALENT BARREL AMOUNTS)		
Oil, gas and natural gas liquids sales	$	54	52	63
Production and operating expenses		(12)	(17)	(17)
Depreciation, depletion and amortization		(5)	(14)	(27)
General and administrative expenses directly related to oil and gas producing activities		(1)	(2)	(1)
Reduction of carrying value of oil and gas properties		--	(96)	--
Income tax benefit (expense)		(13)	35	(12)
Results of operations for oil and gas producing activities	$	23	(42)	6
Depreciation, depletion and amortization per equivalent barrel of production	$	2.40	6.20	9.04

The preceding Total and International results of oil and gas producing activities tables exclude $19 million, $28 million and $66 million in 2002, 2001 and 2000, respectively, related to discontinued operations.

Quantities of Oil and Gas Reserves

Set forth below is a summary of the reserves that were evaluated by independent petroleum consultants for each of the years ended 2002, 2001 and 2000.

	2002		2001		2000	
	ESTIMATED	AUDITED	ESTIMATED	AUDITED	ESTIMATED	AUDITED
Domestic	12%	61%	67%	9%	80%	17%
Canada	31%	--%	43%	--%	100%	--%
International	100%	--%	100%	--%	100%	--%

Estimated reserves are those quantities of reserves which were estimated by an independent petroleum consultant. Audited reserves are those quantities of reserves 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 2002; Paddock Lindstrom & Associates and Gilbert Laustsen Jung Associates, Ltd. in 2001; and Paddock Lindstrom & Associates in 2000. 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, 2002.

	TOTAL			
	OIL (MMBBLS)	GAS (BCF)	NATURAL GAS LIQUIDS (MMBBLS)	TOTAL (MMBOE)
Proved reserves as of December 31, 1999	439	2,785	55	958
Revisions of estimates	(3)	95	4	17
Extensions and discoveries	31	569	6	132
Purchase of reserves	24	80	--	37
Production	(37)	(417)	(7)	(113)
Sale of reserves	(48)	(67)	(8)	(68)
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
Proved developed reserves as of:				
December 31, 1999	264	2,465	52	728
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

	DOMESTIC			
	OIL (MMBBLS)	GAS (BCF)	NATURAL GAS LIQUIDS (MMBBLS)	TOTAL (MMBOE)
Proved reserves as of December 31, 1999	249	2,275	51	679
Revisions of estimates	(3)	101	4	18
Extensions and discoveries	21	504	5	110
Purchase of reserves	21	53	--	30
Production	(29)	(355)	(6)	(94)
Sale of reserves	(33)	(57)	(8)	(51)
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
Proved developed reserves as of:				
December 31, 1999	214	1,960	48	589
December 31, 2000	192	2,087	42	582
December 31, 2001	167	1,988	48	546
December 31, 2002	135	2,802	117	719

	CANADA			
	OIL (MMBBLS)	GAS (BCF)	NATURAL GAS LIQUIDS (MMBBLS)	TOTAL (MMBOE)
Proved reserves as of December 31, 1999	32	506	4	120
Revisions of estimates	3	(6)	--	2
Extensions and discoveries	3	65	1	15
Purchase of reserves	3	27	--	7
Production	(5)	(62)	(1)	(16)
Sale of reserves	--	(6)	--	(1)
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
Proved developed reserves as of:				
December 31, 1999	29	501	4	117
December 31, 2000	30	508	4	119
December 31, 2001	124	1,923	40	485
December 31, 2002	119	1,816	33	455

	INTERNATIONAL			
	OIL (MMBBLS)	GAS (BCF)	NATURAL GAS LIQUIDS (MMBBLS)	TOTAL (MMBOE)
Proved reserves as of December 31, 1999	158	4	--	159
Revisions of estimates	(3)	--	--	(3)
Extensions and discoveries	7	--	--	7
Purchase of reserves	--	--	--	--
Production	(3)	--	--	(3)
Sale of reserves	(15)	(4)	--	(16)
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
Proved developed reserves as of:				
December 31, 1999	21	4	--	22
December 31, 2000	10	--	--	10
December 31, 2001	7	--	--	7
December 31, 2002	6	--	--	6

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, 1999	57	165	13	97
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, 1999	37	36	--	43
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 DECEMBER 31,		
	2002	2001	2000
	(IN MILLIONS)		
Future cash inflows	$ 38,399	21,769	37,974
Future costs:			
Development	(2,053)	(1,860)	(1,267)
Production	(9,076)	(7,682)	(7,329)
Future income tax expense	(8,737)	(3,050)	(8,553)
Future net cash flows	18,533	9,177	20,825
10% discount to reflect timing of cash flows	(8,168)	(4,162)	(8,760)
Standardized measure of discounted future net cash flows	$ 10,365	5,015	12,065

	DOMESTIC DECEMBER 31,		
	2002	2001	2000
	(IN MILLIONS)		
Future cash inflows	$ 20,571	9,861	29,144
Future costs:			
Development	(1,122)	(793)	(916)
Production	(5,871)	(3,774)	(5,661)
Future income tax expense	(3,911)	(759)	(6,346)
Future net cash flows	9,667	4,535	16,221
10% discount to reflect timing of cash flows	(4,157)	(1,734)	(6,592)
Standardized measure of discounted future net cash flows	$ 5,510	2,801	9,629

	CANADA DECEMBER 31,		
	2002	2001	2000
	(IN MILLIONS)		
Future cash inflows	$ 13,799	9,011	5,686
Future costs:			
Development	(633)	(922)	(85)
Production	(2,600)	(3,292)	(616)
Future income tax expense	(3,999)	(2,006)	(1,967)
Future net cash flows	6,567	2,791	3,018
10% discount to reflect timing of cash flows	(2,677)	(1,195)	(1,241)
Standardized measure of discounted future net cash flows	$ 3,890	1,596	1,777

	INTERNATIONAL DECEMBER 31,		
	2002	2001	2000
	(IN MILLIONS)		
Future cash inflows	$ 4,029	2,897	3,144
Future costs:			
Development	(298)	(145)	(266)
Production	(605)	(616)	(1,052)
Future income tax expense	(827)	(285)	(240)
Future net cash flows	2,299	1,851	1,586
10% discount to reflect timing of cash flows	(1,334)	(1,233)	(927)
Standardized measure of discounted future net cash flows	$ 965	618	659

Future cash inflows are computed by applying year-end prices (averaging $27.99 per barrel of oil, adjusted for transportation and other charges, $3.88 per Mcf of gas and $17.07 per barrel of natural gas liquids at December 31, 2002) to the year-end quantities of proved reserves. This is 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 $2.1 billion of future development costs, $547 million, $410 million and $128 million are estimated to be spent in 2003, 2004 and 2005, respectively.

Future development costs include not only development costs, but also future dismantlement, abandonment and rehabilitation costs. Included as part of the $2.1 billion of future development costs are $535 million of future dismantlement, abandonment and rehabilitation costs.

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

The preceding Total and International standardized measure of discounted future net cash flows tables exclude $21 million, $299 million and $407 million in 2002, 2001 and 2000, 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,		
	2002	2001	2000
	(IN MILLIONS)		
Beginning balance	$ 5,015	12,065	4,465
Sales of oil, gas and natural gas liquids, net of production costs	(2,402)	(2,126)	(1,989)
Net changes in prices and production costs	9,122	(11,878)	9,582
Extensions, discoveries, and improved recovery, net of future development costs	1,471	582	2,702
Purchase of reserves, net of future development costs	888	2,480	512
Development costs incurred during the period which reduced future development costs	175	314	113
Revisions of quantity estimates	(61)	(316)	457
Sales of reserves in place	(1,879)	(84)	(818)
Accretion of discount	692	1,708	532
Net change in income taxes	(2,673)	3,340	(4,152)
Other, primarily changes in timing	17	(1,070)	661
Ending balance	$ 10,365	5,015	12,065

The preceding table excludes $21 million, $299 million, $407 million and $303 million as of December 31, 2002, 2001, 2000 and 1999, respectively, related to discontinued operations.

15. Supplemental Quarterly Financial Information (Unaudited)

Following is a summary of the unaudited interim results of operations for the years ended December 31, 2002 and 2001.

		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

		2001				
		FIRST QUARTER	SECOND QUARTER	THIRD QUARTER	FOURTH QUARTER	FULL YEAR
		(IN MILLIONS, EXCEPT PER SHARE AMOUNTS)				
Oil, gas and natural gas liquids sales	$	961	665	521	646	2,793
Total revenues	$	981	680	533	670	2,864
Net earnings (loss) before cumulative effect of change in accounting principle	$	351	136	85	(518)	54
Net earnings (loss)	$	400	136	85	(518)	103
Net earnings (loss) per common share:						
Basic						
Net earnings (loss) before cumulative effect of change in accounting principle	$	2.70	1.03	0.65	(4.13)	0.34
Cumulative effect of change in accounting principle		0.38	--	--	--	0.39
Total basic	$	3.08	1.03	0.65	(4.13)	0.73
Diluted						
Net earnings (loss) before cumulative effect of change in accounting principle	$	2.59	1.01	0.64	(4.13)	0.34
Cumulative effect of change in accounting principle		0.37	--	--	--	0.38
Total diluted	$	2.96	1.01	0.64	(4.13)	0.72

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 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.

The second, third and fourth quarters of 2001 include $77 million, $10 million and $892 million, respectively, of reductions of carrying value of oil and gas properties. The after-tax effect of these expenses was $62 million, $7 million and $542 million, respectively. The per share effect of these quarterly reductions was $0.48, $0.05 and $4.30, 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. Oil, gas and natural gas liquids sales for the first, second, third and fourth quarters of 2001 exclude $50 million, $45 million, $50 million and $42 million, respectively, related to discontinued operations.

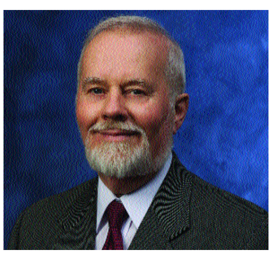
16. Pending Merger (Unaudited)

On February 24, 2003, Devon and Ocean Energy Inc. (“Ocean”) announced their intention to merge. In the transaction, Devon will issue 0.414 of a share of its common stock for each outstanding share of Ocean common stock. Also, Devon will assume approximately $1.8 billion of debt from Ocean. The transaction is subject to approval by the stockholders of both companies, as well as certain regulatory approvals. If approved, the transaction is expected to be consummated shortly after the stockholder meetings.

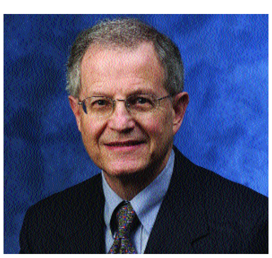
Ocean’s December 31, 2002 proved oil and gas reserves totaled 593 million barrels of oil equivalent located in the United States, West Africa and other International locations.

John W. Nichols, 87, as a co-founder of Devon, he was named Chairman Emeritus in 1999. Nichols was chairman of the board of directors since 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.

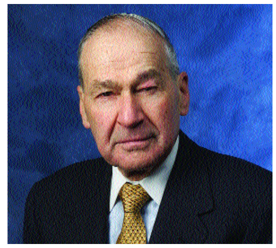
J. Larry Nichols, 60, is a co-founder of Devon. He was named chairman of the board of directors in 2000. He has been a director since 1971, president since 1976 and chief executive officer since 1980. Nichols serves on the board of governors of the American Stock Exchange. He serves as a director of Smedvig ASA, Baker Hughes Incorporated and several trade associations that are relevant to the company's business.



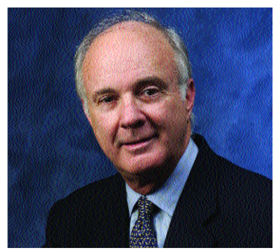
Thomas F. Ferguson, 66, has been on the board of directors since 1982 and is the chairman of the Audit Committee. He is the managing director of United Gulf Management Ltd., a wholly-owned subsidiary of Kuwait Investment Projects Co. KSC. Ferguson represents Kuwait Investment Projects Co. on the boards 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.



David M. Gavrin, 68, has been on the board of directors since 1979 and serves as the chairman of the Compensation Committee. Gavrin has been a private investor since 1989 and is currently a director of MetBank Holding Corp. and United American Energy Corp., an independent power producer. From 1978 to 1988, he was a general partner of Windcrest Partners, and for 14 years prior to that, he was an officer of Drexel Burnham Lambert Inc.



Michael E. Gellert, 71, has been on the board of directors since 1971 and is chairman of the Nominating Committee. Since 1967, Gellert has been a general partner of Windcrest Partners, a private investment partnership in New York City. 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 being a Devon director, Gellert is on the boards of High Speed Access Corp., Humana Inc., Seacor Smit Inc., Six Flags Inc., Travelers Series Fund Inc., Dalet Technologies and Smith Barney World Funds.



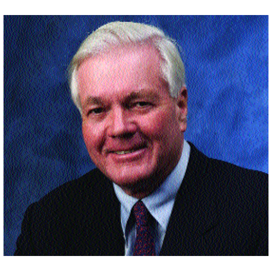
John A. Hill, 61, was elected to the board of directors in 2000. Hill has been with First Reserve Corp., an oil and gas investment management company, since 1983 and is currently the vice chairman and managing director. Prior to joining First Reserve, Hill was president, chief executive officer and director 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.

William J. Johnson, 68, 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 sole shareholders. 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, 54, was elected to the board of directors in 1998. Kanovsky was a co-founder of Northstar Energy Corp., Devon's Canadian subsidiary, and has served on the board of directors since 1982. Kanovsky is president of Sky Energy Corp., a privately held energy corporation. He continues to be active in the Canadian energy industry and is currently a director of ARC Resources Ltd. and Bonavista Petroleum Corp.

J. Todd Mitchell, 44, was elected to the board of directors in January 2002. From 1993 to 2002, Mitchell served on the board of directors of Mitchell Energy & Development Corp. Mitchell has been president of GPM Inc., a family-owned investment company, since 1998. He also has held the position of president of Dolomite Resources Inc., a privately owned mineral exploration and investments company, since 1987 and as chairman of Rock Solid Images, a privately owned seismic data analysis software company, since 1998.

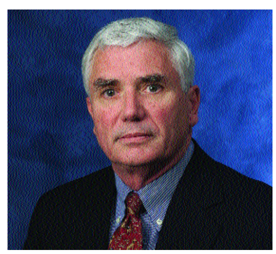
Robert A. Mosbacher, Jr., 51, was elected to the board of directors in 1999. Since 1986, Mosbacher has served as president and chief executive officer of Mosbacher Energy Co. and has been vice chairman of Mosbacher Power Group since 1995. Mosbacher was previously a director of PennzEnergy Co. and served on the Executive Committee. He is currently a director of JPMorgan Chase and Co., Houston Regional Board and is on the Executive Committee of the U.S. Oil & Gas Association.



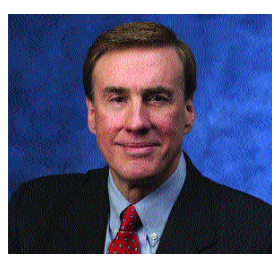
Robert B. Weaver, 64, was elected to the board of directors in 1999. Weaver was an energy finance specialist for Chase Manhattan Bank, N.A., where he was in charge of the worldwide energy group from 1981 until his retirement in 1994. From 1998 to 1999, Weaver served as a director and chairman of the Audit Committee and member of the Compensation Committee of PennzEnergy Co. and its predecessor Pennzoil Co.

SENIOR VICE PRESIDENTS

Brian J. Jennings, 42, was elected to the position of senior vice president, Corporate Development, in July 2001. 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 launched 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.



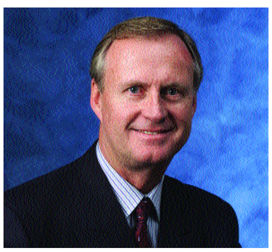
J. Michael Lacey, 57, was elected to the position of senior vice president, Exploration and Production, in 1999. Lacey joined Devon as vice president of Operations and Exploration in 1989. Prior to his employment with Devon, Lacey served as general manager for Tenneco Oil Co.'s Mid-Continent and Rocky Mountain Divisions. He is a registered professional engineer and a member of the Society of Petroleum Engineers and the American Association of Petroleum Geologists. Lacey holds undergraduate and graduate degrees in petroleum engineering from the Colorado School of Mines.



Duke R. Ligon, 61, was elected to the position of senior vice president and general counsel in 1999. Ligon started at Devon as vice president and general counsel in 1997. Prior to joining Devon, Ligon practiced energy law for 12 years, serving in his latest position as a partner at the law firm of Mayer, Brown & Platt in New York City. He also was senior vice president and managing director for Investment Banking at Bankers Trust Co. in New York City for 10 years. Additionally, Ligon worked 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 Westminister College and a law degree from the University of Texas School of Law.

Marian J. Moon, 52, was elected senior vice president, Administration, in 1999. Moon has been with Devon for 19 years, serving in various capacities, including manager of Corporate Finance. Before joining Devon, Moon worked for 11 years at Amarex Inc., an Oklahoma City based oil and natural gas production and exploration firm, where her last position held was treasurer. Moon is a member of the American Society of Corporate Secretaries. She is a graduate of Valparaiso University.



John Richels, 52, was elected to the position of senior vice president, Canadian Division, in 2001. Prior to his election to senior vice president, Richels held the position of chief executive officer of Northstar Energy Corp., Devon's Canadian subsidiary. Richels served as Northstar's executive vice president and chief financial officer from 1996 to 1998 and was on its 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 has served as a director of a number of publicly traded companies and is 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.

Darryl G. Smette, 55, was elected to the position of senior vice president, Marketing, in 1999. Smette previously held the position of vice president, Marketing and Administrative Planning, since 1989 and joined Devon in 1986 as manager of Gas Marketing. His marketing background includes 15 years with Energy Reserves Group Inc./BHP Petroleum (Americas) Inc., where his latest position was director of Marketing. Smette is an oil and gas industry instructor, approved by the University of Texas Department of Continuing Education. He is a member of the Oklahoma Independent Producers Association, Natural Gas Association of Oklahoma and the American Gas Association. Smette holds an undergraduate degree from Minot State College and a master's degree from Wichita State University.

William T. Vaughn, 56, was elected to the position of senior vice president, Finance, in 1999. Vaughn previously served as Devon's vice president of Finance, overseeing commercial banking functions, accounting, tax and information services since 1987. Prior to that, he was controller of Devon from 1983 to 1987. Vaughn's previous experience includes two years at Marion Corp., where his latest position was as controller, and seven years with Arthur Young & Co., where he last served as audit manager. He is a Certified Public Accountant and a member of the American Institute of Certified Public Accountants. Vaughn is a graduate of the University of Arkansas with a Bachelor of Science degree.

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 methane: 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.

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
2001				
First	$ 66.75	52.30	58.20	60,614,200
Second	$ 62.65	48.50	52.50	66,350,200
Third	$ 55.25	30.55	34.40	93,386,100
Fourth	$ 41.25	31.45	38.65	81,883,800
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**

INVESTOR INFORMATION

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Telephone: (405) 235-3611
Fax: (405) 552-4550

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Devon Energy Corporation
20 North Broadway
Oklahoma City, OK 73102-8260

GULF AND GULF COAST OPERATIONS
Devon Energy Corporation
Devon Energy Tower
1200 Smith Street, Suite 3300
Houston, TX 77002

INTERNATIONAL OPERATIONS
Devon Energy Corporation
3 Allen Center
333 Clay Street, 10th Floor
Houston, TX 77002

CANADIAN OPERATIONS
Devon Canada Corporation
3000, 400 - 3rd Avenue S.W.
Calgary, Alberta T2P 4H2

SHAREHOLDER ASSISTANCE
For information about transfer or exchange of shares, dividends, address changes, account consolidation, multiple mailings, lost certificates and Form 1099:

Devon Energy Common Shareholders
Wachovia Bank, N.A.
1525 West W.T. Harris Blvd.
Bldg. 3C, 3rd Floor
Charlotte, NC 28262-1153
Toll Free: (800) 829-3432

Northstar Exchangeable Shareholders
CIBC Mellon Trust Company
P.O. Box 1036
Adelaide Street Postal Station
Toronto, Ontario M5C 2K4
Toll Free: (800) 387-0825

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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
Telephone: (405) 552-4570
Fax: (405) 552-7818
E-mail: judy.roberts@dvn.com

ANNUAL MEETING
Our annual shareholders' meeting will be held at 10 a.m. Central Time on Wednesday, June 11, 2003, in the Kirkpatrick Room, third floor of the Bank One Center, 100 North Broadway, Oklahoma City, OK.

INDEPENDENT AUDITORS
KPMG LLP
Oklahoma City, OK

STOCK TRADING DATA
Devon Energy Corporation's common stock is traded on the American Stock Exchange (symbol: DVN). There are approximately 25,000 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.

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