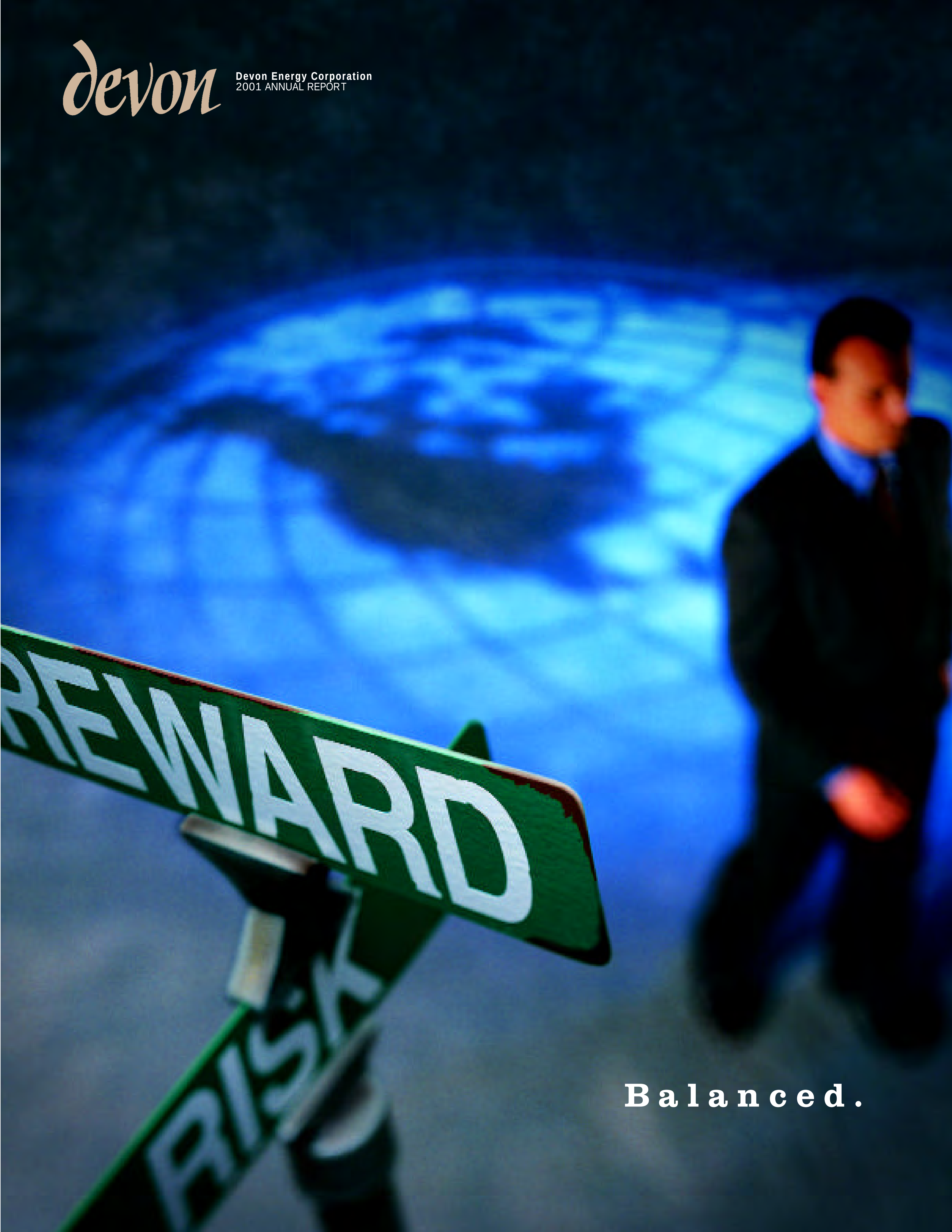
devon

Devon Energy Corporation
2001 ANNUAL REPORT



B a l a n c e d .

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.*

"Balanced," the theme of this annual report, resulted from a suggestion by Rocky Mountain Division employee Susan Gilbert. Gilbert's winning entry was one of nearly 300 suggestions from employees in the company's annual report theme contest.

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. 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 & 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.

Five-Year Highlights

Devon's acquisition of Anderson Exploration on October 15, 2001 was recorded using the purchase method of accounting. Therefore, the information presented below includes Anderson's results from October 15 through December 31, 2001 only. Devon's acquisition of Mitchell Energy did not close until January 24, 2002. Therefore, Mitchell's results are not included for any period reported.

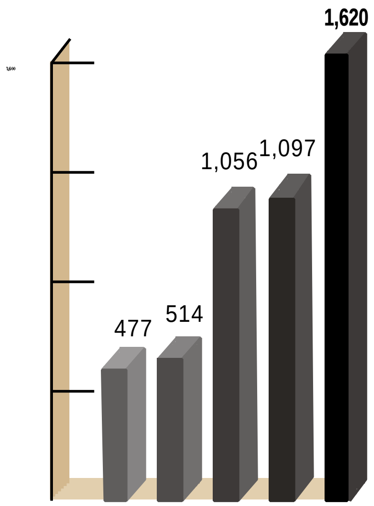
Year Ended December 31,		1997	1998	1999	2000	2001	Last Year Change
Financial Data (1) (Millions, except per share data)							
Total revenues	$	1,014	706	1,278	2,784	**3,075**	10%
Cash expenses (2)	$	457	382	615	1,036	**1,134**	9%
Cash margin	$	557	324	663	1,748	**1,941**	11%
Non-cash expenses							
Effects of changes in foreign currency exchange rates	$	6	16	(13)	3	**13**	333%
Reduction of carrying value of oil & gas properties	$	641	423	476	–	**1,003**	NM
Change in accounting principle	$	–	–	–	–	**(49)**	NM
Other non-cash expenses (including deferred taxes)	$	128	121	354	1,015	**871**	(14%)
Net earnings (loss)	$	(218)	(236)	(154)	730	**103**	(86%)
Net earnings (loss) applicable to common shareholders	$	(230)	(236)	(158)	720	**93**	(87%)
Net earnings (loss) per share							
Basic	$	(3.35)	(3.32)	(1.68)	5.66	**0.73**	(87%)
Diluted	$	(3.35)	(3.32)	(1.68)	5.50	**0.72**	(87%)
Weighted average common shares outstanding - basic		69	71	94	127	**128**	1%
Weighted average common shares outstanding - diluted		75	77	99	132	**130**	(2%)
Cash dividends per common share (3)	$	0.09	0.10	0.14	0.17	**0.20**	18%

December 31,		1997	1998	1999	2000	2001	Last Year Change
Total assets	$	1,965	1,931	6,096	6,860	**13,184**	92%
Debentures exchangeable into shares of ChevronTexaco Corporation common stock (4)	$	–	–	760	760	**649**	(15%)
Other long-term debt (5)	$	576	885	1,656	1,289	**5,940**	361%
Stockholders' equity	$	1,007	750	2,521	3,277	**3,259**	(1%)
Working capital	$	56	7	123	305	**162**	(47%)
Property Data (1)							
Proved reserves (net of royalties)							
Oil (MMBbls)		219	235	496	459	**586**	28%
Gas (Bcf)		1,403	1,477	2,950	3,458	**5,477**	58%
Natural gas liquids (MMBbls)		24	33	68	62	**121**	95%
Total (MMBoe) (6)		477	514	1,056	1,097	**1,620**	48%
10% present value (7) (Millions)	$	2,100	1,528	5,812	17,737	**7,174**	(60%)

Year Ended December 31,	1997	1998	1999	2000	2001	Last Year Change
Production (net of royalties)						
Oil (MMBbls)	32	26	32	43	**44**	2%
Gas (Bcf)	186	198	304	426	**498**	17%
Natural gas liquids (MMBbls)	3	3	5	7	**8**	14%
Total (MMBoe) (6)	66	62	88	121	**135**	12%

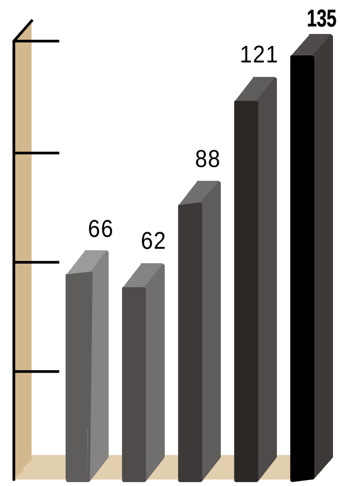
(1) Data has been restated to reflect the 1998 merger of Devon and Northstar and the 2000 merger of Devon and Santa Fe Snyder in accordance with the pooling-of-interests method of accounting. The mergers of Santa Fe with Snyder Oil and Devon with PennzEnergy were recorded as purchases on May 5, 1999 and August 17, 1999, respectively. Revenues, expenses and production in 2001 include two and one-half months attributable to the Anderson Exploration acquisition and in 1999 include eight months activity attributable to the Snyder Oil transaction and four and one-half months activity attributable to the PennzEnergy transaction.
(2) Includes merger costs in 1998, 1999, 2000 and 2001 of $13 million, $17 million, $60 million and $1 million respectively.
(3) The cash dividends per share presented are not representative of the actual amounts paid by Devon on a historical basis because of mergers accounted for as poolings. For the years 1997 through 2000, Devon's historical cash dividends per share were $0.20 in each year.
(4) Debentures exchangeable into seven million shares of ChevronTexaco Corporation common stock beneficially owned by Devon.
(5) Includes preferred securities of subsidiary trust of $149 million in years 1997 and 1998.
(6) Gas converted to oil at the ratio of 6 Mcf:1 Bbl.
(7) Before income taxes.

Reserves
(NET OF ROYALTIES) (MMBoe)



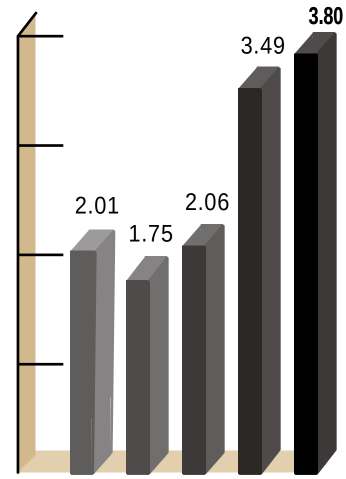
Drilling and acquisitions drove proved reserves up almost 50%...

Oil and Gas Production
(NET OF ROYALTIES) (MMBoe)



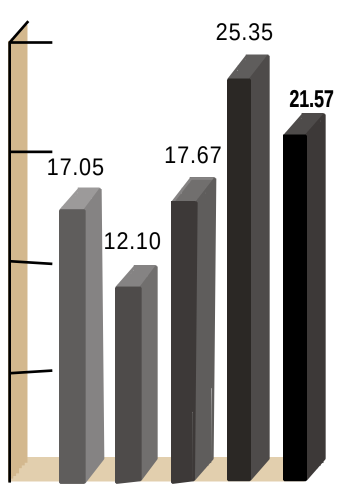
...and oil and gas production to record levels.

Average Gas Price Received
($ per Mcf)



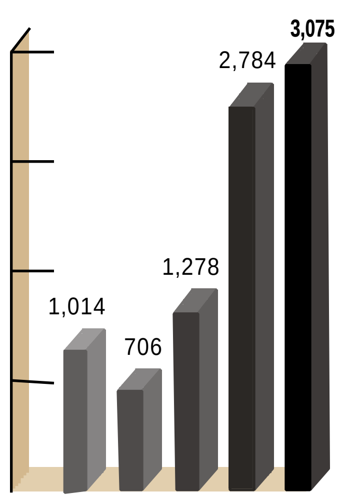
Natural gas prices reached a new high...

Average Oil Price Received
($ per Bbl)



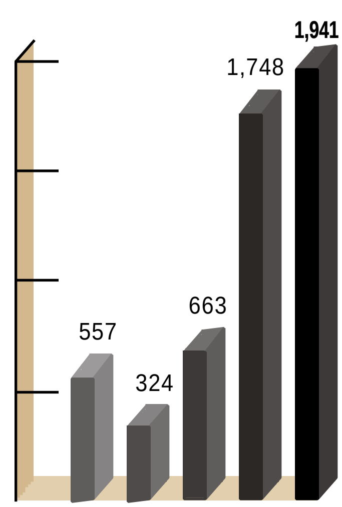
...while oil prices fell.

Total Revenues
($ Millions)



Total revenues topped $3 billion for the first time in Devon's histor y...

Cash Margin*
($ Millions)



* Revenues less cash expenses

...driving our cash margin to nearly $2 billion.

Letter to Shareholders

We have a

balanced

strategy

for long-term

success.

Dear Fellow Shareholders

For Devon, 2001 was a year of great challenge and achievement. Oil and gas production climbed to record highs. Total revenues topped $3 billion, also an all-time record. We successfully drilled over 1,400 oil and gas wells and we completed the largest acquisition in our history—driving oil and gas reserves to the highest levels ever. More importantly, oil and gas reserves per share, production per share and cash margin per share all rose to record levels. The year was clearly one of great growth and achievement for Devon. Yet lower oil and gas prices at the end of 2001 led to a non-cash impairment charge to the book value of our oil and gas properties. As a result, net earnings for 2001 declined. How can we make sense of all this?

J. Larry Nichols

We operate in a volatile external environment. Oil and gas prices rapidly rise and fall in response to a myriad of psychological, meteorological, political and economic forces. Our short-term results reflect this volatility in oil and gas prices. However, Devon has delivered superior performance over the long run by looking beyond short-term price trends. We have focused our efforts on building concentrations of high quality oil and gas properties that can be efficiently operated. We have strived to drill and acquire properties that provide opportunities for future growth. We have positioned our operations in areas with access to strong and growing markets for our products. And we have disposed of properties that fail to meet these criteria. In 2001, we made important progress in each of these areas.

On August 14, 2001 we announced the first of two major acquisitions—the purchase of Mitchell Energy. Just three weeks later, on September 4, we announced a second major transaction. After a year-long evaluation of Canadian producer Anderson Exploration, we struck an agreement to acquire that company. Because the Anderson acquisition was structured as an all-cash tender, we were able to complete it very quickly. On October 15, 2001, less than two months after the announcement, we closed the acquisition of Anderson. Because the Mitchell acquisition required a special meeting of each company's shareholders to approve the deal, it was necessary to file a proxy with the Securities and Exchange Commission. Following the Commission's review of the accounting treatment, reserve data and compliance with other regulatory requirements related to the two acquisitions, we held the shareholders' meetings. On January 24, 2002, the transaction was completed following overwhelming approval. These acquisitions nearly doubled our proved oil and gas reserves, placing Devon among the largest independent energy companies. More importantly, the transactions provide Devon with an outstanding array of internal growth opportunities.

Undertaking two major acquisitions simultaneously was not a decision made lightly. Were it not for our extensive experience in integrating major acquisitions, we would not have had the confidence to proceed with both. Their distinct geographic locations and tightly focused operations made the concurrent integration of Mitchell and Anderson possible. We dedicated two separate integration teams to the effort. Devon's Canadian management team in Calgary, Alberta, is leading the integration of Anderson. Our experienced U.S.-based team is handling the integration of Mitchell.

The Mitchell acquisition would not have been possible without the leadership and support of Mitchell's founder and CEO, George Mitchell. Following the acquisition, Mr. Mitchell's son, Todd, joined Devon's board of directors. We welcome the Mitchell family as Devon shareholders and Todd Mitchell as a Devon director.

Balancing the Cost of Debt and Equity

In the acquisitions of Mitchell and Anderson, Devon issued approximately 30 million new shares and took on about $6.7 billion in incremental debt. Our decision to fund the majority of the two transactions with debt rather than equity was based in part on the relative cost of capital. Because of the Federal Reserve's efforts to stimulate the U.S. economy, interest rates were at historic lows. Further, with oil and gas prices entering a cyclical downturn, the stock prices of independent producers were well off their 52-week highs. This diminished the attractiveness of using Devon's stock as acquisition currency.

We funded the cash portion of the acquisitions with a combination of a $3 billion five-year term note and $3 billion of 10- and 30-year debentures. Our average interest rate on this new debt is only 5% and we have no meaningful principal repayment obligations until 2004. Furthermore, as of this writing, we have almost $1 billion in cash and unused credit lines. Even though we doubled the size of the company, we retained financial flexibility.

Balanced for Growth

The Anderson acquisition provides Devon with an abundance of drilling opportunities in the Western Canadian Sedimentary Basin. Anderson spent decades assembling its land positions and developing oil and gas properties in western Canada. In recent years, Anderson was also one of Canada's most active acquirers of exploration land and seismic data. Devon inherits that exploration legacy. Over a third of our 2002 drilling and facilities budget is planned for Canada, and we expect Canada to be a major contributor to Devon's growth far into the future.

The Mitchell acquisition brings to Devon a major new growth asset in north Texas, the Barnett Shale. With over 525,000 net acres in the play area, Devon has the dominant position. We acquired 800 wells that are producing 350 million cubic feet of gas per day. With thousands of potential drilling locations and drilling success rates of almost 100%, we expect the Barnett Shale to become Devon's fastest growing producing area. In addition, Mitchell brings to Devon significant gas transmission and processing facilities. These assets provide us with ready access to several major natural gas markets including the rapidly growing Dallas/Fort Worth Metroplex.

In addition to the Mitchell and Anderson acquisitions, Devon added to its inventory of low-risk growth opportunities with the launch of a significant new coalbed methane project. The production of natural gas from underground coal deposits, or "coalbed methane," utilizes technology and expertise honed by Devon since the 1980s. Devon's drilling success rate approaches 100% in these low-risk gas projects. During 2001, Devon established a dominant position in the Cherokee coalbed methane play in Kansas and Oklahoma. We acquired over 400,000 net undeveloped acres, drilled more than 130 wells and began construction of a major gas transmission system. We expect the Cherokee coalbed methane project to provide Devon with a source of gas reserves and production growth for years to come.

In addition to dramatically expanding Devon's oil and gas property base during 2001, we made significant progress in bringing focus to our operations. The acquisitions of PennzEnergy and Santa Fe Snyder in 1999 and 2000 brought us many assets outside North America. Some of these assets were accompanied by drilling and capital commitments. We said at that time that we would honor these commitments, evaluate the results and narrow the focus of our international operations. Our goal was to keep a few select international areas that had meaningful potential for a company Devon's size. That process is nearing completion. This will leave Devon with high-potential international assets in Azerbaijan, China and West Africa. Also during 2001, we completed a thorough review of all of our North American assets. We identified properties that had high operating costs, limited growth potential or that were no longer significant to Devon. In aggregate, the domestic and international assets that we have identified for sale represent approximately 15% of Devon's proved oil and gas reserves following the acquisition of Mitchell. The sale of these properties will leave Devon with a high-margin oil and gas property base with significant growth potential. As an added benefit, we expect to generate sales proceeds in excess of $1 billion to be used primarily for debt repayment.

A Balanced Outlook

In my letter in last year's annual report, I cautioned that while the oil and gas price outlook for 2001 remained strong, market conditions could change quickly. No one could have known how true that warning would prove to be. As of the writing of this letter, the natural gas price is less than half of that just one year ago. However, when the balance of supply and demand inevitably shifts again in favor of the producer, Devon stands ready to reap the rewards.

As I look ahead to the coming years I have every reason to be optimistic about our future. The bold steps taken during 2001 have positioned us with an oil and gas property base of exceptional quality. We have an enviable balance of low-risk development projects and high-impact exploration opportunities. And, we have talented and dedicated staff spanning the organization. We have the right balance of resources to unlock for tomorrow the value that lies within Devon today.

J Larry Nichols

J. Larry Nichols
CHAIRMAN, PRESIDENT ANDCEO
March 18, 2002

A balanced view of the future requires looking beyond the obvious.

Members of Devon's senior management answer Wall Street's questions.

Devon appears to be shifting its resources away from acquisitions and more toward drill-bit oriented growth. Why is that?

Larry Nichols, Chairman, President and CEO:
As Devon has grown, the likelihood of a single acquisition significantly impacting our overall operations has diminished. At the same time, the dramatic expansion of our undeveloped property base through the Anderson and Mitchell acquisitions has provided a bigger and better inventory of drilling prospects than ever before. Our acquisition of Mitchell Energy early in 2002 brought a vast inventory of low-risk development drilling locations. The acreage that Mitchell held in the Barnett Shale is expected to provide Devon with a source of drilling opportunities and production growth for years to come. Anderson Exploration had a well-earned reputation as one of Canada's most active exploration companies. The eight million net undeveloped acres brought to Devon by Anderson includes some of the most attractive exploration acreage in North America. Consequently, with more attractive internal growth opportunities and fewer potentially significant acquisitions, we are devoting more resources to drilling. However, we will continue to watch for the opportunity to make value-added acquisitions when appropriate.

Devon has used oil and gas price swaps and costless collars to protect the prices on a significant portion of its 2002 and 2003 oil and gas production. What is your hedging philosophy and has it changed?

Darryl Smette, Senior Vice President — Marketing:
Devon's hedging philosophy has not changed. We believe that when properly used, oil and gas price hedges mitigate risk. We have used hedging a number of times in the past to support a minimum rate of return from a specific project or to capture value from an unsustainable spike in oil or gas prices.

Early in 2001, when gas prices were at all-time highs, we elected to take advantage of the situation and lock-in those high prices. We protected a portion of our 2001 and 2002 gas production against a steep price decline.

While Devon's hedging philosophy did not change, our circumstances did. In acquiring Anderson and Mitchell, we chose to substantially increase long-term debt in a weakening oil and gas price environment. This increased the importance of protecting a minimum level of cash flow from which to fund our capital requirements. In response, we chose to hedge additional 2002 and 2003 volumes to provide a price floor for a larger portion of our oil and gas production. As we entered 2002, we had hedges in place for nearly 40% of our expected 2002 gas production and for more than half of our expected 2002 oil production. In addition, we are adding to our 2003 hedge positions as the opportunity arises.

What is your exploration and development budget for 2002 and how do you plan to fund it?

Mike Lacey, Senior Vice President — Exploration and Production:
For 2002, we are deploying a relatively robust exploration and development budget in spite of weakening current oil and gas prices. Our $1.3 billion exploration and development budget should allow us to participate in over 2,000 oil and gas wells. About three-fourths of this budget will be directed toward lower-risk development projects intended to contribute near-term production growth. By maintaining a strong production profile, we are positioning Devon to benefit from stronger oil and gas prices when they inevitably recover. The remaining one-fourth of our capital budget, or a little more than $300 million, will be invested in longer-term high potential projects. While these projects will not contribute to Devon's near-term production growth, they provide the opportunity to add significant reserves and production over the longer term.

We expect oil and gas production to climb to record levels in 2002. This level of production and the price protection that we have provided through hedging ensure that cash flow from operations will be our principle source of exploration and development drilling capital. In the event the outlook for oil and gas prices improves or deteriorates significantly, we will adjust our 2002 drilling budget commensurately.

Devon has historically carried very little debt on its balance sheet. Why have you recently increased debt levels?

Bill Vaughn, Senior Vice President — Finance:
Devon typically maintains a very strong balance sheet. This provides ready access to capital at reasonable interest rates allowing us to seize opportunities when they arise. Such was the case late last year when we had the chance to simultaneously pursue the acquisitions of Mitchell Energy and Anderson Exploration. The opportunity to significantly enhance the quality of Devon's oil and gas property base and improve our growth profile justified the increase in indebtedness.

This is not the first time that we have temporarily increased our debt levels to capture an extraordinary opportunity. When Devon acquired PennzEnergy in 1999, it was the largest acquisition in our history. Immediately after closing the transaction, our debt relative to our size was just about the same as it is today. We quickly restored our balance sheet by issuing new equity and requiring the conversion into equity of the convertible debt that we had outstanding. Just as we did then, we now have a plan in place to reduce indebtedness and strengthen our balance sheet. We will accomplish this with the proceeds from the sale of non-core assets and cash flow generated from our oil and gas properties.

What role do you see for the Canadian Division in Devon's future?

John Richels, Senior Vice President — Canadian Division:
Canada represents an important component of Devon's intermediate and long-term growth plans. In 1998, we established a significant presence in Canada by merging with Northstar. Our decision was driven by the opportunities emerging in Canada. Historically, shortages of natural gas pipeline capacity from Canada to major North American gas markets had suppressed gas prices in Canada. This discouraged additional exploration for oil and gas and the development of the required pipeline and processing infrastructure. As a consequence, many of the oil and gas prone areas of Canada were under-explored relative to the U.S. However, conditions have been improving in Canada. New pipelines have been constructed and older ones have been expanded. As a result, Canadian natural gas prices have improved relative to those in the U.S. Stronger relative gas prices are stimulating the development of infrastructure into additional areas.

The Anderson acquisition leverages the operational expertise that we have established in Canada. The assets strengthen our position in the major producing basins in western Canada and the Anderson staff bring a wealth of human talent. The properties also included eight million net acres of undeveloped land, including two million net acres in the vast, under-explored far north. This ensures that Canada will remain a significant focus area for Devon far into the future.

In the acquisition of Mitchell Energy, you acquired significant gas transmission and processing assets. What is Devon's midstream strategy?

Darryl Smette:
Devon prefers to own midstream assets that support our exploration and production goals. When we produce a large portion of the gas requiring transportation or processing in a midstream operation, we often find it desirable to both own and operate the facilities. This allows us to control the cost of transporting and processing our gas and helps ensure that we access the best available markets. Another benefit of owning midstream operations is the ability to add capacity as we foresee the need. Furthermore, controlling the producing assets that support a midstream operation reduces the risk of owning midstream assets.

In addition to moving Devon's own gas and oil, the Marketing and Midstream Division also meets the needs of other producers by providing reliable midstream services and market outlets for their products. Transporting and processing natural gas for unrelated parties is an integral part of Devon's midstream business.

Devon has acquired two large companies in the last six months. What gives you the confidence that you will be able to integrate them successfully?

Marian Moon, Senior Vice President — Administration:
Devon has completed 10 major acquisitions since our birth as a public company in 1988. As a result, we have learned a great deal about integrating people and operations. We have developed processes that are applied and improved upon with each succeeding transaction. One of the first steps in a successful integration involves establishing a transition team. Our teams include employees from every functional area. The teams meet on a regular basis to discuss transition issues, especially those that impact more than one functional area. They get to know their counterparts within the acquired company and begin to understand how human resources, operations and management information systems can be brought together. They are charged with selecting the best processes, systems and policies from each organization.

Our employees are our most valuable assets, especially during the integration process. Without their creativity, flexibility, energy and willingness to take on new challenges, Devon could not have successfully grown into the company we are today.

Devon Creates
Marketing and Midstream Division

During 2001, Devon incorporated its U.S. midstream activities with marketing, creating a sixth operating division. The Marketing and Midstream Division operates more than 10,000 miles of pipeline systems and 12 natural gas processing plants. These facilities produce approximately 72,000 bar rels per day of natural gas liquids, or NGLs, for Devon.

The division's responsibilities include marketing natural gas, crude oil and NGLs. The division is also responsible for 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 parties.

One of the division's most profitable activities is the processing of natural gas for the extraction of NGLs. NGLs include ethane, propane, butane and natural gasoline. Approximately 85% of all NGLs produced in the U.S. are consumed in the petrochemical industr y, in the manufacture of motor gasoline and for residential and commercial heating.

Devon's Bridgeport, Texas gas plant processes much of the gas supplying the growing Dallas/Fort Worth Metroplex.

Getting the **most** from our oil and gas properties demands a **balance** of **talent** and **technology**.

Primary Exploration and Production Areas

A Balance of Opportunity

The acquisitions of Anderson Exploration in October 2001 and Mitchell Energy in January 2002, dramatically expanded our portfolio of oil and gas properties. Combined, the two transactions almost doubled Devon's proved oil and gas reserves. The acquired properties lie almost entirely within two of Devon's historical core operating areas: the Permian/Mid-Continent and Canada. They enhance these positions and tighten our focus on North America. Following the divestitures of non-core properties planned for 2002, over 95% of Devon's oil and gas production will be from North America.

Devon's North American oil and gas properties are concentrated in four geographic areas. Our Canadian operations are focused in the Western Canadian Sedimentary Basin in Alberta and British Columbia. In the U.S., we are focused on the Permian/Mid-Continent, the Rocky Mountain and Gulf regions. The company has carefully selected these areas based on access to oil and gas markets, growth potential and overall profitability. In each of these areas Devon is among the largest producers. This concentration has allowed us to improve our operating and capital efficiency in each of our major areas of operations.

Today, Devon has by far the biggest and best drilling inventory in our history. This inventory provides opportunities ranging from low-risk, near-term development projects to high-impact exploration ventures. Our low-risk growth prospects include thousands of undrilled locations within our coalbed methane and Barnett Shale projects. In addition to these non-conventional projects, we have hundreds of low- and moderate-risk conventional drilling opportunities spanning all of our North American core areas. While the majority of our 2002 capital budget is devoted to these low- and moderate-risk projects, we also have meaningful exposure to potential reserve additions through exploration. These exploration opportunities range from the Mackenzie Delta of Canada's far north to the deepwater offshore West Africa. The following pages contain additional information about our areas of operations and our plans for 2002.

Properties in the U.S.

Rocky Mountain Division

The Rocky Mountain Division includes Devon's properties in Wyoming, Utah, Colorado and northern New Mexico. While our assets in the Rocky Mountains include significant conventional oil and gas properties, 2002 activity is focused primarily on coalbed methane projects.

The Rocky Mountain Division manages three of Devon's four significant coalbed methane projects. The most active of these is in Wyoming's Powder River Basin. Devon began drilling coalbed methane wells in the Powder River Basin in 1998. To date, we have drilled almost 1,400 wells. We exited 2001 with net Powder River coalbed methane sales at about 90 million cubic feet of natural gas per day. This rate is expected to continue to rise as more wells are drilled and de-watered.

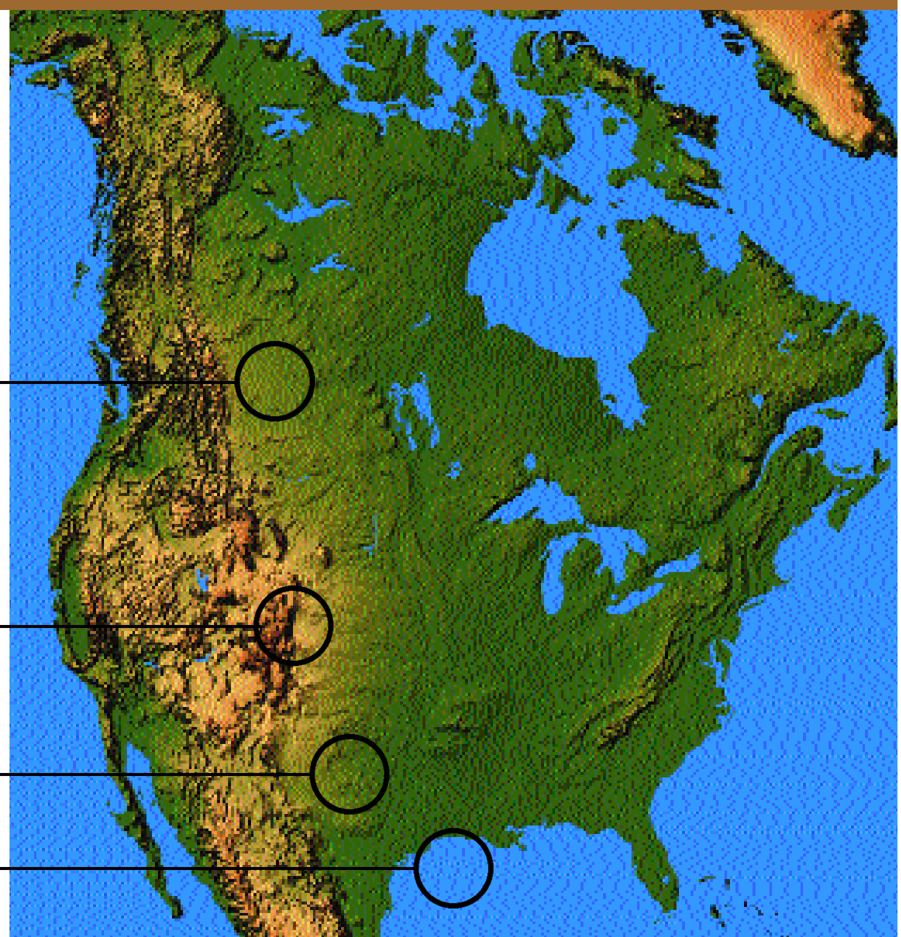
Plans call for drilling more than 200 Powder River wells in 2002. This will include roughly 170 wells in existing producing areas and 90 wells in new project areas. Current production is primarily from the Wyodak coal formation. In addition, the company has several new projects developing the deeper Big George coals. Success in the Big George would significantly expand the potential of Devon's 250,000 net acres in this area.

Permian / Mid-Continent Division

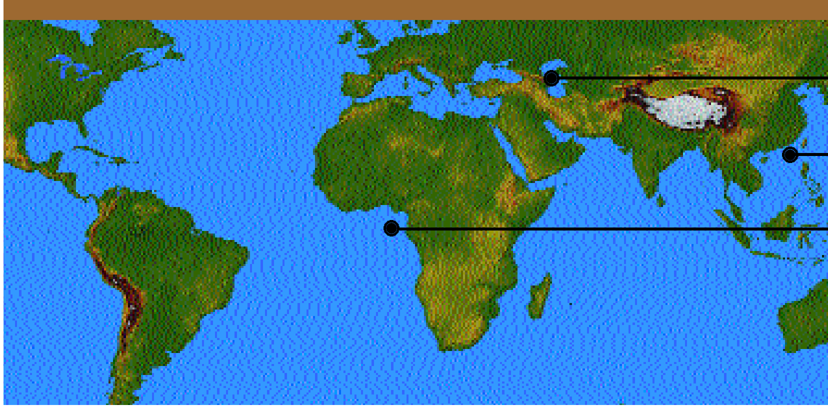
Devon's Permian/Mid-Continent Division includes portions of New Mexico, Texas, Oklahoma, Kansas, Mississippi and Louisiana. This area encompasses a wide

continued on page 18

NORTH AMERICA



INTERNATIONAL



Rig hands conduct drilling operations on a Devon natural gas well. We plan to drill over 2,000 wells in 2002.

variety of geologic formations and productive depths. The Permian/Mid-Continent produces more oil than any other division in the company and a significant portion of Devon's natural gas. Our Permian/Mid-Continent production has historically come from conventional oil and gas properties. However, we recently established dominant positions in two non-conventional gas plays in the Permian/Mid-Continent: the Barnett Shale and the Cherokee coalbed methane project.

The most significant asset brought to Devon in our recent acquisition of Mitchell Energy was our interest in the Barnett Shale of north Texas. The Barnett Shale is known as a "tight gas" formation. This means that in its natural state, the formation is resistant to the production of natural gas. Mitchell spent decades understanding how to efficiently develop and produce this gas. The resulting technology yielded a low-risk and highly profitable natural gas play. Devon holds 525,000 net acres and over 800 producing wells in the Barnett Shale. Our average working interest is approximately 95%. The Barnett Shale is a unique, unconventional gas resource that offers immediate low-risk production growth and the potential for significant reserve additions.

The key to unlocking the gas trapped within the tight shale is a recently perfected completion technique called light sand fracturing. Light sand fracturing yields much better results than earlier techniques and costs less. Not only are new wells fractured when completed, but older wells can be refractured with excellent results. Refractured wells often exceed their original flow rates, even after years of production. In spite of recent improvements in fracture technology, we currently recover less than 10% of the gas in place. Further technological improvements could unlock additional potential in the future.

In 2002, we plan to drill 300 new Barnett Shale wells and refracture 144 wells. We also plan to drill eight exploratory wells outside the core development area with the hope of expanding the productive area. The potential to expand the play outside the core area, to drill increased density wells, to refracture existing wells and to recover additional gas with improved technology all offer tremendous upside potential. The Barnett Shale is expected to be an important growth area for Devon for many years to come.

The other important new asset in the Permian/Mid-Continent Division is the Cherokee coalbed methane project. Coalbed methane is natural gas produced from underground coal deposits. Unlike conventional natural gas wells, coalbed methane wells initially produce water along with small quantities of gas. Over time, gas production increases as the water is removed from the reservoir and the gas trapped within the coal is released.

During the first half of 2001, we acquired over 400,000 net acres within the Cherokee area of southeast Kansas and northeast Oklahoma. We began drilling in the second half of 2001 and had drilled 131 wells by the end of the year. Plans for 2002 are to drill 200 new wells and further refine completion techniques. Aggregate gas production should begin to reach significant levels in the second half of 2002 as drilling and de-watering progress. If the wells in this project perform as we believe they will, we expect to ultimately drill more than 1,000 wells in the play.

Mobile water tanks line up in preparation for a fractur e treatment. This process is the key to unlocking the gas potential of the Barnett Shale in north Texas.

Gulf Division

The Gulf Division manages our properties in the Gulf of Mexico and onshore in south Texas and south Louisiana. The division contributes roughly 17% of current company-wide gas production, mostly from the shallow waters of the Gulf of Mexico. The shallow water Gulf, or "shelf," is a mature producing area with relatively high field decline rates. These characteristics present challenges to Gulf operators. Devon has responded to those challenges by continually utilizing technological advances in the search for new reserves.

Devon is applying four-component seismic technology to identify prospects on large tracts of our shelf acreage. Traditional seismic techniques have not been useful in imaging reservoirs lying below shallow gas reservoirs and salt deposits. Four-component seismic, or 4C, is now allowing our geoscientists to more accurately picture these unexplored formations. We have conducted two large 4C seismic surveys offshore Louisiana. In early 2002, we began drilling and have achieved early success on prospects resulting from a 300 square mile 4C survey in the West Cameron area. We are currently interpreting the results of our second 4C survey. This one covers 360 square miles in the Eugene Island – South Marsh Island area.

Another response to declining shelf production has been the move into deeper water. The deepwater Gulf is believed to contain some of the largest remaining undiscovered oil and gas reserves in North America. Because deepwater exploration is capital intensive, Devon's strategy is to move cautiously. Our main focus is on prospects in water depths for which infrastructure and production technology are well established. We limit our exploration exposure in the deepwater to participation in a few wells each year. Furthermore, we generally share the risk of deepwater exploration wells with industry partners. One of the deepwater exploration wells we plan to drill in 2002 will assess one of the largest untested structures in the Gulf. The Cortes Prospect lies in 3,300 feet of water and covers most of four 5,000-acre blocks in the Port Isabel area. The gross reserve potential of this 18,000 foot deep prospect exceeds one trillion cubic feet of gas. Devon has a 25% working interest in Cortes.

Another of our deepwater projects is expected to begin producing in 2002. Devon has a 48% working interest in the Manatee Field which is located on Green Canyon block 155 in about 1,900 feet of water. Production will be from two wells in a sub-sea system. These wells will produce into the nearby Angus Field and then flow to the Bullwinkle platform in 1,350 feet of water. Devon's share of production is expected to exceed 10,000 barrels of oil per day.

A further source of oil and gas reserves and production growth lies in the Gulf Coast region onshore south Texas. Devon's activities in this area have focused on exploration in the Edwards, Wilcox and Frio/Vicksberg trends. In 2001, we drilled five successful exploration wells and 32 development wells. As a result, over the course of the year Devon's share of production doubled to more than 60 million cubic feet per day. The Mitchell acquisition, completed in early 2002, adds additional production and undeveloped acreage in the south Texas area. With a large, high-quality inventory of additional drilling locations, we expect south Texas to be a source of continued growth.

Properties in Canada

Devon's acquisition of Anderson Exploration in late 2001 dramatically increased the significance of Canada to Devon's overall property portfolio and enhanced our growth potential. We sought to expand our presence in Canada because we believe that many of its oil and gas-prone areas are underdeveloped or underexplored. Devon's properties in Canada offer a balance of drilling opportunities spanning the entire risk-reward spectrum.

The Anderson acquisition strengthened Devon's holdings in almost all of the important producing basins in Canada. One such area is the Deep Basin located in western Alberta, along the British Columbia border. Devon had sought for years to obtain a significant acreage position in the Deep Basin. However, other operators, including Anderson, already controlled most of the acreage. As a result of the acquisition, Devon is now a leading Deep Basin operator and holds over 800,000 net acres. Furthermore, the profitability of our operations is enhanced by ownership in nine major gas processing plants in the area.

During 2002, we plan to drill about 85 wells in the Deep Basin. Reserve targets range in size from five to 15 billion cubic feet of gas. These reservoirs tend to be rich in liquids, producing up to 100 barrels with each million cubic feet of gas. Due to the multizone nature of this area, drilling success rates are quite high, in the 70% to 90% range.

Another focus area for Devon's 2002 drilling program will be the Slave Point region of northwestern Alberta and northeastern British Columbia. This area includes the Hamburg/Ladyfern area where some of Canada's largest recent gas discoveries have occurred. Devon plans to drill eight Slave Point wells in 2002, including five at Ladyfern.

In 2003, Devon plans to bring several previous deep gas discoveries on stream in the Grizzly Valley area of the Foothills of northeastern British Columbia. Since our initial discovery here in 1998, Devon has drilled 11 successful wells. We expect to commence initial production at a combined rate of about 50 million cubic feet of gas per day to Devon.

The Anderson acquisition significantly increased our holdings in the Foothills. We have interests ranging from 49% to 55% in over 1.2 million gross acres in the area. While Devon had focused on exploring for deep gas reservoirs in this area, Anderson had achieved considerable success in drilling for shallower formations. The Anderson acquisition affords us the opportunity to extend that company's shallow gas development onto Devon's acreage and to apply Devon's deep gas exploration expertise to the Anderson acreage.

One of the highest potential exploration assets we acquired from Anderson was its 1.5 million net acres in Canada's most prospective exploratory region, the far north. Our position includes a working interest in nearly half of all the lands held by the industry in the Mackenzie Delta and shallow water Beaufort Sea. Devon plans to continue the long-term exploration program begun by Anderson. These plans include active 2D and 3D seismic programs both onshore and offshore. Beginning in 2002, Devon plans to drill up to four wells annually in the Mackenzie Delta. While it will be years before construction of a pipeline will allow production to begin, this area could hold significant long-term potential for Devon.

International Properties

Devon's assets outside North America were acquired in the PennzEnergy and Santa Fe transactions. Since acquiring these properties, we have critically evaluated each one and have disposed of many. Devon has identified our assets in Argentina and Indonesia for sale in 2002 as part of our non-core asset dispositions. From interests in 13 countries, we now are focusing on just three international areas.

In Azerbaijan, Devon holds a 5.6% carried interest in a world-class oil development project, the Azeri-Chirag-Gunashli Field. Significant production from this multibillion barrel oil field is still several years away pending completion of an additional export pipeline.

In China, Devon is the largest acreage holder in the Pearl River Mouth Basin in the South China Sea. Development of our Panyu Project is underway and we expect first oil production from two offshore platforms in late 2003. We expect Devon's share of production to approximate 15,000 barrels per day.

Our international exploration efforts are focused primarily on the deepwater off West Africa. Devon holds over two million net acres in these waters where several important discoveries have been made by the industry in recent years. In 2002, we plan to drill a test well on our Rita Prospect located offshore Congo.

North of 60°

North of 60° refers to the area of Canada north of the 60 degree line of latitude. It includes the Yukon Territory, the Northwest Territories and Nunavut. The Geological Survey of Canada estimates that the area contains 65 trillion cubic feet of natural gas and seven billion barrels of oil. Much of that potential lies in the Mackenzie Delta and under the shallow waters of the Beaufort Sea.

Devon's 2001 acquisition of Anderson Exploration established the company as the largest holder of exploration licenses and concession acreage in the Mackenzie Delta and Beaufort Sea regions. This exploratory acreage could provide Devon with oil and gas production and reserve growth opportunities well into the future.

OPERATING STATISTICS BY AREA

		Permian	Mid–Continent	Total Permian/ Mid–Continent	Rocky Mountains	Onshore Gulf	Offshore Gulf
Producing Wells at Year–End		8,437	3,707	12,144	3,742	1,098	850
2001 Production (Net of Royalties)							
Oil (MMBbls)		11	2	13	2	1	10
Gas (Bcf)		67	55	122	112	24	118
NGLs (MMBbls)		2	2	4	1	–	1
Total (MMBoe)(1)		24	13	37	22	5	31
Average Prices							
Oil Price (Per Bbl)	$	21.09	23.29	21.34	24.64	22.49	23.12
Gas Price (Per Mcf)	$	3.83	4.26	4.02	3.72	4.10	4.78
NGLs Price (Per Bbl)	$	16.77	17.63	17.24	17.32	2.88	16.73
Year–End Reserves (Net of Royalties)							
Oil (MMBbls)		117	9	126	24	4	37
Gas (Bcf)		346	562	908	1,114	102	275
NGLs (MMBbls)		15	18	33	9	2	8
Total (MMBoe)(1)		189	121	310	219	23	91
Year–End Present Value of Reserves (Millions)(2)							
Before Income Tax	$	960	659	1,619	859	153	639
After Income Tax	$						
Year–End Leasehold (Net Acres in Thousands)							
Producing		383	432	815	308	220	333
Undeveloped		566	986	1,552	1,374	55	579
Wells Drilled During 2001		198	204	402	634	54	55
2001 Exploration, Development & Facilities Expenditures (Millions)(3)	$	283	164	447	187	123	293
Estimated 2002 Exploration, Development & Facilities Expenditures (Millions)(4)	$	25 – 30	360 – 410	385 – 440	65 – 75	85 – 95	140 – 165

(1) Gas converted to oil at the ratio of 6 Mcf:1 Bbl.
(2) Estimated future revenue to be generated from the production of proved reserves, net of estimated future production and development costs, discounted at 10%.
(3) Excludes $31 million for construction of gas transmission systems.
(4) Excludes $135 to $165 million expected to be spent on gas services assets. Does not include the cost to acquire Mitchell Energy.

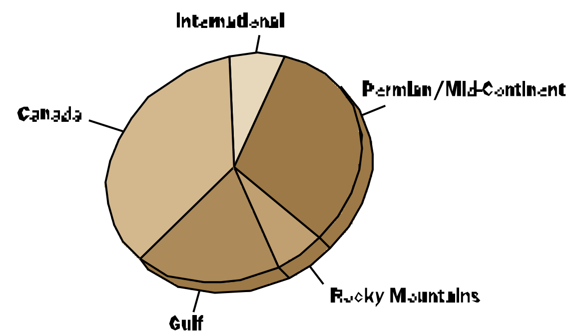
ELEVEN YEAR PROPERTY DATA (1)

		1991	1992	1993	1994	1995
Reserves (net of royalties)						
Oil (MMBbls)		236	280	274	312	334
Gas (Bcf)		410	645	736	782	895
Natural Gas Liquids (MMBbls)		4	7	7	12	16
Total (MMBoe) (2)		308	394	404	454	499
10% Present Value (Millions) (3)	$	812	1,376	1,098	1,561	1,986
Production (net of royalties)						
Oil (MMBbls)		22	26	30	30	31
Gas (Bcf)		52	80	106	101	113
Natural Gas Liquids (MMBbls)		–	1	1	1	1
Total (MMBoe) (2)		31	40	49	48	51
Average Prices						
Oil (Per Bbl)	$	16.04	14.94	13.12	13.12	15.14
Gas (Per Mcf)	$	1.41	1.63	1.77	1.69	1.43
Natural Gas Liquids (Per Bbl)	$	16.39	12.57	11.75	10.41	10.06
Oil, Gas and Natural Gas Liquids (Per Boe) (2)	$	13.93	13.18	12.18	12.00	12.58
Production and Operating Expense per Boe (2)	$	5.86	5.35	5.04	4.95	4.85

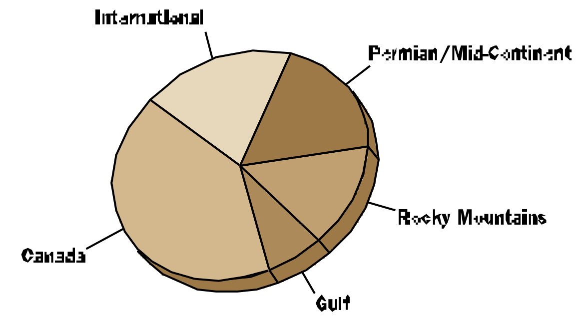
(1) Data has been restated to reflect the 1998 merger of Devon and Northstar and the 2000 merger of Devon and Santa Fe Snyder in accordance with the pooling–of–interests method of accounting.
(2) Gas converted to oil at the ratio of 6 Mcf:1Bbl.
(3) Before income taxes.

TOTAL GULF	TOTAL U.S.	CANADA	INTERNATIONAL	TOTAL COMPANY
1,948	17,834	13,997	1,468	33,299
11	26	8	10	44
142	376	113	9	498
1	6	2	–	8
36	95	29	11	135
23.06	22.36	17.84	22.57	21.57
4.67	4.17	2.73	1.41	3.80
16.87	17.15	16.43	16.15	16.98
41	191	166	229	586
377	2,399	2,625	453	5,477
10	52	56	13	121
114	643	659	318	1,620
792	3,270	2,744	1,160	7,174
	2,801	1,596	917	5,314
553	1,676	2,486	209	4,371
634	3,560	10,233	7,838	21,631
109	1,145	292	108	1,545
416	1,050	318	149	1,517
225 – 260	675 – 775	420 – 500	65 – 105	1,160 – 1,380

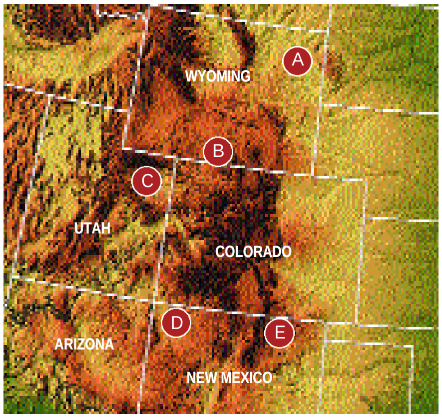
2002 EXPLORATION, DEVELOPMENT & FACILITIES BUDGET



PROVED OIL & GAS RESERVES BY DIVISION



1996	1997	1998	1999	2000	2001	5–YEAR COMPOUND GROWTH RATE	10–YEAR COMPOUND GROWTH RATE
375	219	235	496	459	**586**	9%	10%
1,158	1,403	1,477	2,950	3,458	**5,477**	36%	30%
19	24	33	68	62	**121**	45%	41%
587	477	514	1,056	1,097	**1,620**	23%	18%
4,095	2,100	1,528	5,812	17,737	**7,174**	12%	24%
33	32	26	32	43	**44**	6%	7%
123	186	198	304	426	**498**	32%	25%
2	3	3	5	7	**8**	32%	NM
56	66	62	88	121	**135**	19%	16%
17.62	17.05	12.10	17.67	25.35	**21.57**	4%	3%
1.79	2.01	1.75	2.06	3.49	**3.80**	16%	10%
13.97	12.61	8.09	13.30	20.87	**16.98**	4%	–
14.95	14.54	11.05	14.35	22.47	**22.05**	8%	5%
5.31	4.78	4.45	4.31	4.94		–	(1%)



Rocky Mountains

A Powder River Coalbed Methane

Profile

- 200,000 net undeveloped and 50,000 net developed acres in northeastern Wyoming.
- Initial position obtained in 1992 acquisition.
- Produces coalbed methane from the Fort Union Coal formations at 300' to 2,000'.
- 25.7 million barrels of oil equivalent reserves at 12/31/01.

2001 Activity

- Drilled 435 coalbed methane wells (279 wells awaiting connection to pipeline system at year-end).
- Connected 340 wells to gas sales.
- More than doubled annual net production.
- Acquired 8,000 net acres of Big George coal seam acreage.
- First gas sales from a Big George pilot.

2002 Plans

- Connect remaining wells drilled in 2001 to pipeline system.
- Drill 200 to 250 additional coalbed methane wells.
- Expand infrastructure in the Pine Tree and House Creek pilot areas.
- Establish gas sales from additional Big George pilots.

B Washakie

Profile

- 70% working interest in 228,000 acres in southern Wyoming.
- Obtained in 2000 acquisition.
- Produces gas from multiple formations at 6,800' to 10,300'.
- 61.5 million barrels of oil equivalent reserves at 12/31/01.

2001 Activity

- Drilled and completed 21 gas wells.
- Executed successful recompletion program.

2002 Plans

- Drill and complete 3 gas wells.
- Conduct additional drilling and recompletion operations as justified by market conditions.

C Bluebell/Altamont

Profile

- 93% working interest in 37,000 acres in northeast Utah.
- Obtained in 1999 acquisition.
- Produces premium priced yellow crude oil from the Wasatch formation at 8,000' to 15,000'.
- Developing oil potential in lower Green River formation and gas potential in upper Green River formation.
- 11.9 million barrels of oil equivalent reserves at 12/31/01.

2001 Activity

- Drilled and completed 5 wells.
- Performed 23 recompletions.

2002 Plans

- Identify additional recompletion opportunities and infill drilling locations.
- Resume drilling and recompletion activities as justified by market conditions.

D NEBU/32-9 Units

Profile

- 25% working interest in 50,000 acres in the San Juan Basin of northwestern New Mexico.
- Initially developed in the late 1980s and early 1990s.
- Includes 168 coalbed methane wells.
- Produces primarily coalbed methane from the Fruitland Coal formation at 3,000'.
- 27.2 million barrels of oil equivalent reserves at 12/31/01.

2001 Activity

- Recavitated 16 wells.
- Installed wellhead compression.
- Installed 33 pumping units for water removal.
- Drilled and completed 4 conventional Mesaverde/Dakota gas wells.

2002 Plans

- Drill and complete up to 20 conventional Mesaverde/Dakota gas wells (pending partner approval).
- Recavitate up to 23 wells.

E Vermejo Park Ranch

Profile

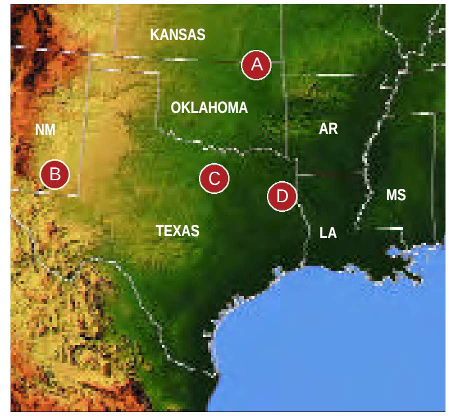
- Located on the Colorado/New Mexico border in the Raton Basin.
- Initial 25% working interest plus 25% royalty interest in 280,000 prospective coalbed methane acres.
- Working interest increases to 50% after meeting economic hurdles.
- Obtained in 1999 acquistion.
- Produces coalbed methane from the Vermejo and Raton Coal formations at 1,000' to 2,300'.
- 30.5 million barrels of oil equivalent reserves at 12/31/01.

2001 Activity

- Drilled and completed 103 of 104 coalbed methane wells.
- Drilled 5 core holes and 4 stratigraphic test wells to further delineate formation.
- Installed 26 pumping units for water removal.
- Restimulated 10 wells.
- Expanded production infrastructure.

2002 Plans

- Drill and complete 108 coalbed methane wells.
- Expand water disposal facilities including the drilling of 1 water disposal well and deepening another.
- Install additional pumping units for water removal.
- Drill 2 conventional test wells.
- Further expand field infrastructure.



Permian/Mid-Continent

A Cherokee Coalbed Methane

Profile

- 400,000 net acres in southeast Kansas and northeast Oklahoma.
- 100% working interest.
- Initiated in 2001.
- Produces coalbed methane from multiple coal seams at 600' to 1,100'.
- Access to major gas pipelines.
- 18.1 million barrels of oil equivalent reserves at 12/31/01.

2001 Activity

- Drilled 131 and completed 51 coalbed methane wells.
- Initiated construction of gas pipeline system in Kansas.
- Acquired additional acreage.

2002 Plans

- Complete wells drilled in 2001.
- Drill 200 additional coalbed methane wells.
- Drill 9 salt-water disposal wells.
- Recomplete 29 wells.
- Complete construction of pipeline system.

B Southeast New Mexico

Profile

- 358,000 net acres in southeast New Mexico.
- 60% average working interest.
- Key fields include Indian Basin, Catclaw Draw and Outland/Gaucho.
- Produces oil and gas from multiple formations at 2,000' to 17,000'.
- 56.1 million barrels of oil equivalent reserves at 12/31/01.

2001 Activity

- Acquired 113,000 net acres.
- Drilled and completed 100 wells.

2002 Plans

- Drill up to 40 wells as justified by market conditions.

C Barnett Shale

Profile

- 525,000 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'.
- 800 wells producing 345 MMCFD.
- Approximately 300 million barrels of oil equivalent reserves at 1/24/02.

2002 Plans
- Drill and complete 300 gas wells.
- Refracture 144 wells.
- Continue pilot projects outside core area.
- Acquire additional seismic and acreage.

D Carthage/Bethany Area

Profile
- 65% to 85% working interest in 77,000 acres located in east Texas.
- Obtained in 1999 acquisition.
- Produces from the Cotton Valley, Travis Peak and Pettit formations at 5,800’ to 9,500’.
- Includes 550 producing wells.
- 59.4 million barrels of oil equivalent reserves at 12/31/01.

2001 Activity
- Drilled and completed 46 wells.
- Performed 17 well recompletion/workover program.

2002 Plans
- Complete 5 wells drilling in late 2001.
- Drill 19 wells.
- Continue recompletion/workover program.

Gulf – Shelf

A South Marsh Island 23 Area

Profile
- 100% working interest in Eugene Island block 156; South Marsh Island blocks 22, 23, 34, 47, 48; 50% working interest in South Marsh Island blocks 21 and 32.
- Obtained in 1999 acquisition.
- Located offshore Louisiana in 100’ of water.
- 19 wells producing from the lower Pliocene/upper Miocene formations at 3,900’ to 15,000’.
- 5.1 million barrels of oil equivalent reserves at 12/31/01.

2001 Activity
- Drilled and completed 1 well.
- Performed 2 recompletes/workovers.
- Installed compression at South Marsh Island 23G and 48B.

2002 Plans
- Recomplete 4 wells.
- Interpret pulsed neutron logs.
- Continue well workover program.
- Reprocess and interpret 3D seismic.
- Develop drilling plans in the area.

B High Island 582

Profile
- 37% working interest.
- Obtained in 1999 acquisition.
- Located offshore Texas in 440’ of water.
- Produces primarily gas from sands at depths of 4,000 to 12,000’.
- 6.1 million barrels of oil equivalent reserves at 12/31/01.

2001 Activity
- Drilled 3 additional wells following the 2000 Cyrus discovery.
- Initiated construction on a new production platform.

2002 Plans
- Complete construction and installation of production facilities.
- Complete pipeline construction.
- Complete 4 wells and commence oil and gas production in the second half of 2002.

C West Cameron 4C Area

Profile
- Includes 17 offshore blocks where Devon is applying 4 component (4C) seismic technology.

2001 Activity
- Acquired 1 additional lease block.
- Evaluated 300 square mile 4C survey.
- Identified 4 drilling opportunities.

2002 Plans/Activity
- Drilled successful well on West Cameron 536 (100% WI) in Q1.
- Initiate drilling of 3 additional wells.
- Evaluate additional prospects.

D Eugene Island 330 Area

Profile
- Includes 100% working interest in Eugene Island blocks 316 and 329, 98% in Eugene Island block 337, 50% in the south half of block 315 and 23% in block 330.
- Obtained in 1999 acquisition.
- Located offshore Louisiana in 250’ of water.
- Produces oil and gas from sands at 1,200’ to 9,000’.
- 4.6 million barrels of oil equivalent reserves at 12/31/01.

2001 Activity
- Drilled and completed 5 wells at Eugene Island 330.
- Performed 4 recompletes/workovers at Eugene Island 330.
- Drilled and completed 2 wells at Eugene Island 337.

2002 Plans
- Drill and complete 3 wells.
- Perform 4 recompletes/workovers.

Shelf Exploration Prospects

Profile

E **Grays**
- Galveston 424
- Located offshore Texas in 100’ of water.
- Target formation: Miocene sands at 10,000’ to 15,000’.
- Net unrisked reserve potential: 6 MMBoe.

F **Thunder**
- Eugene Island 342
- Located offshore Louisiana in 270’ of water.
- Target formation: Miocene Sub-Salt at 15,000’ to 18,000’.
- Net unrisked reserve potential: 6 MMBoe.
- Drill to earn interest in 5 additional blocks.

2002 Plans
- Finalize geophysical analysis.
- Bring in industry partners.
- Drill exploratory test wells.

Gulf – 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 acquisition.
- 16.8 million barrels of oil equivalent reserves at 12/31/01.

2001 Activity
- Produced and monitored Angus.
- Evaluated possible T sand for sidetrack at Angus.
- Drilled 1 well at Manatee.
- Completed design of sub-sea system at Manatee.

2002 Plans
- Complete sub-sea development at Manatee.
- First production expected in late 2002.

B Mississippi Canyon 661

Profile
- 25% working interest in Mississippi Canyon 661 (Firebird).
- Obtained in 2000 acquisition.
- Located offshore Louisiana in 850’ of water.
- Produces oil and gas from multiple Pliocene sands at 10,500’.
- 2.1 million barrels of oil equivalent reserves at 12/31/01.

2001 Activity
- Drilled and completed 1 well.
- Brought Firebird on to production.

2002 Plans
- Produce and monitor.

C Mississippi Canyon 110

Profile
- 25% working interest in Mississippi Canyon 110 (Orion).
- Obtained in 2000 acquisition.
- Located offshore Louisiana in 1,200’ of water.
- Produces oil and gas from multiple Pliocene sands at 6,000’ to 7,000’.
- 2.1 million barrels of oil equivalent reserves at 12/31/01.

2001 Activity
- Drilled and completed 1 well.

2002 Plans
- Commence limited production in Q1.
- Full production expected in Q3 pending completion of compression facilities.

Viosca Knoll 738 & 739 (D)

Profile

- 47% average working interest in Viosca Knoll blocks 738 & 739 (Pecten/Maria).
- Located offshore Mississippi in 600’ to 900’ of water.
- Obtained in 2000 acquisition.
- 2.4 million barrels of oil equivalent reserves at 12/31/01.

2001 Activity

- Brought Pecten discovery well on production in Q1.
- Brought Maria field on to production.

2002 Plans

- Produce and monitor.

Deepwater Exploration Prospects

Profile

E **Cortes**

- Port Isabel 175
- Located offshore Texas in 3,300’ of water.
- Target formation: Oligocene Frio sands at 15,000’ to 18,000’.
- 25% working interest.
- Net unrisked reserve potential: 40 MMBoe.

F **Tuscany East**

- Desoto Canyon 180/224
- Located offshore Louisiana 6,700’ of water.
- Target formation: Middle Miocene sands at 13,500’ to 14,000’.
- 25% working interest.
- Net unrisked reserve potential: 33 MMBoe.

2002 Plans

- Finalize geophysical analysis.
- Drill exploratory test wells.

Gulf – Onshore

South Texas (A)

Profile

- Up to 100% working interest in 449,000 acres.
- Obtained in 1999 acquisition.
- Key areas include Zapata, Agua Dulce/N. Brayton, Refugio and Pettus/Ray Ranch.
- Produces oil and gas from the Edwards, Wilcox and Frio/Vicksburg trends at 1,500’ to 14,000’.
- 18 million barrels of oil equivalent reserves at 12/31/01.

2001 Activity

- Drilled and completed 32 development wells.
- Drilled and completed 5 exploratory wells.
- Acquired additional acreage.

2002 Plans

- Drill 40 development wells.
- Drill 5 exploratory wells.

Patterson Field (B)

Profile

- 50% working interest in 5,000 acres in southern Louisiana.
- Obtained in 1999 acquisition.
- Produces oil and gas from Miocene sands at 10,000’ to 19,000’.
- 1.2 million barrels of oil equivalent reserves at 12/31/01.

2001 Activity

- Drilled and completed 1 well.

2002 Plans/Activity

- Drilled successful exploratory well in Q1.
- Drill 2 additional exploratory wells.
- Evaluate additional prospects.

Canada *(Includes Anderson’s activity for the full year 2001)*

Mackenzie Delta (A)

Profile

- 46% working interest in 3.2 million exploratory acres in the Mackenzie Delta and shallow waters of the Beaufort Sea.
- Largest holder of exploration acreage in this area.
- Drilling limited to winter only.

2001 Activity

- Acquired acreage position through Anderson acquisition.
- Conducted 275 square mile onshore 3D seismic survey.
- Conducted 625 square mile offshore 3D seismic survey.
- Drilled and suspended KURK M15 well.
- Participated in export pipeline discussions with other operators.

2002 Plans

- Complete and test KURK M15 well.
- Drill 3 additional exploratory wells.
- Evaluate offshore seismic and pursue farm-out opportunities.
- Continue export pipeline discussions.

Slave Point (B)

Profile

- 63% average working interest in 300,000 acres in northwestern Alberta and northeastern British Columbia.
- Key areas include Hamburg, Chinchaga, Ladyfern and Wildmint.
- Drilling is primarily winter-only access.
- Produces liquid-rich gas from the Slave Point formation at 8,000’ to 10,000’.
- Gas processing plants at Chinchaga (100% interest) and at Hamburg (60% interest).
- 6 million barrels of oil equivalent reserves at 12/31/01.

2001 Activity

- Drilled and completed 5 Slave Point wells.
- Performed 6 3D seismic surveys.
- Secured pipeline capacity at Ladyfern.

2002 Plans

- Drill 8 exploratory Slave Point wells, 5 at Ladyfern.
- Shoot additional 3D seismic.
- Initiate infrastructure construction at Ladyfern.

N. Alberta Shallow Gas (C)

Profile

- 73% average working interest in 3.8 million acres in north central Alberta.
- Key areas include Springburn, Leismer/Kirby, Cherpeta, Goodfish, Gift, Dawson, Marten Hills and Woodenhouse.
- 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 8,000’.
- 74.7 million barrels of oil equivalent reserves at 12/31/01.

2001 Activity

- Drilled and completed 180 of 220 shallow gas wells in winter program.
- Drilled and completed 12 of 15 oil and gas wells in summer program.
- Drilled and completed 15 of 17 Devonian oil wells.
- Expanded compression and dehydration facilities at Hangingstone, Springburn, West Surmont and Goodfish.

2002 Plans

- Drill 96 shallow gas wells.
- Drill 8 Devonian oil wells.
- Expand gas processing facilities at Goodfish.

Peace River Arch (D)

Profile

- 76% average working interest in 1.6 million acres in western Alberta.
- Key areas include Girouxville, Dunvegan and Pouce Coupe.
- Produces liquids-rich gas and light gravity oil from multiple formations.
- 110.7 million barrels of oil equivalent reserves at 12/31/01.

2001 Activity

- Acquired 778,000 net undeveloped acres through the Anderson acquisition.
- Drilled and completed 126 wells.
- Significant discoveries made at Girouxville and Pouce Coupe.
- Completed construction of Rycroft sour gas plant (Devon WI 45%).

2002 Plans

- Drill 76 wells.
- Construct 5,000 BOD oil battery at Girouxville.
- Continue 3D seismic evaluation at Pouce Coupe.

Deep Basin (E)

Profile

- 48% average working interest in 1.8 million acres in western Alberta.
- Key areas include Wapiti, Elmworth, Bilbo and Hiding.
- Produces liquids rich gas from Cretaceous and Devonian formations at 3,000’ to 13,500’.
- 79.6 million barrels of oil equivalent reserves at 12/31/01.

2001 Activity

- Acquired acreage position through Anderson acquisition.

- Drilled and completed 119 wells.
- Discoveries at Hiding.
- Significant field extensions at Wapiti, Bilbo and Elmworth.

2002 Plans

- Drill 85 wells.
- Complete construction of the Elmworth pipeline and associated facilities.
- Add additional compression at Bilbo.
- Continue field development at Wapiti, Bilbo and Elmworth.

F Foothills

Profile

- 52% working interest in 1.2 million acres in western Alberta and eastern British Columbia.
- Key exploratory areas include Grizzly Valley in northeastern British Columbia and Narraway, Cabin Creek and Findley in west central Alberta.
- High-impact, long-lived reserves.
- Produces gas from multiple formations at 4,000' to 15,000'.
- 84.7 million barrels of oil equivalent reserves at 12/31/01.

2001 Activity

- Acquired 350,000 net undeveloped acres through the Anderson acquisition.
- Drilled and completed 5 exploratory wells in the Grizzly Valley area.
- Drilled and completed 21 wells in the Narraway, Cabin Creek and Findley areas.
- Completed construction of 134 MMCFD gas facility at Narraway (Devon WI 42%).

2002 Plans

- Continue drilling 2 exploratory wells initiated in 2001 in Grizzly Valley.
- Drill 4 additional exploratory wells in the Grizzly Valley area.
- Drill 11 wells in the Narraway, Cabin Creek and Findley areas.

G Heavy Oil

Profile

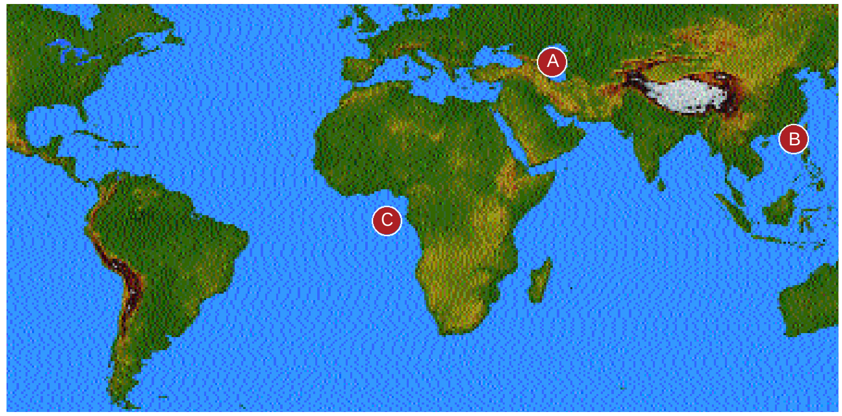
- 81% average working interest in 1 million acres primarily in northeastern Alberta.
- Key areas include Manatokan, Lloydminster, Surmont, Trout, Dover and Jackfish.
- Acreage contains prospects suitable for both conventional and thermal recovery.
- 47 million barrels of conventional and 5 million barrels of thermal reserves at 12/31/01.

2001 Activity

- Drilled and completed 51 of 57 conventional heavy oil wells.
- Drilled 81 delineation wells at Surmont, Trout and Jackfish.
- Converted royalty interest to 13% working interest at Surmont.

2002 Plans

- Drill 50 conventional heavy oil wells.
- Drill 83 delineation wells at Surmont, Trout and Jackfish.



International

A Azerbaijan

Profile

- 5.6% carried interest in 137,000 acres in the Azeri-Chirag-Gunashli (ACG) oil fields offshore Azerbaijan.
- Obtained in 1999 acquisition.
- Oil is exported by pipeline to the west and north.
- Operating and capital cost currently paid by partners under carried interest agreement.
- Anticipate significant production and revenue to Devon commencing in 2005 to 2010.
- 145.8 million barrels of oil equivalent reserves at 12/31/01.

2001 Activity

- Purchased 0.8% additional carried interest.
- Approved the first of 3 field development phases.

2002 Plans

- Continue drilling of 4 extended reach wells on the Chirag 1 platform.
- Convert 3 additional wells to injector wells.
- Begin construction on phase 1 development.
- Receive approval for the Main Export Pipeline from Baku to Ceyhan, Turkey.

B China

Profile

- 4 licensed blocks in the Pearl River Mouth Basin offshore China.
- Obtained in 2000 acquisition.
- Anticipate first oil production in 2003.
- 18.4 million barrels of oil equivalent reserves at 12/31/01.

2001 Activity

- Received approval for development program for Panyu project.
- Initiated fabrication of Panyu facilities.

2002 Plans

- Continue with construction of Panyu facilities.

C Offshore West Africa

Profile

- 4 licensed offshore blocks include: Keta block offshore Ghana, Agali and Kowe blocks offshore Gabon, Marine IX block offshore Congo.
- Obtained in 2000 acquisition.
- Interest in 6 oil producing wells on the Kowe block.
- 6.5 million barrels of oil equivalent reserves at 12/31/01.

2001 Activity

- Acquired 3D seismic data.
- Identified drilling locations for 2002 exploratory wells.
- Secured farmout agreement with partner to participate in Keta block and pay for 3D seismic program.

2002 Plans

- Drill exploration well on Marine IX block.
- Finalize plans for Agali well to be drilled in early 2003.

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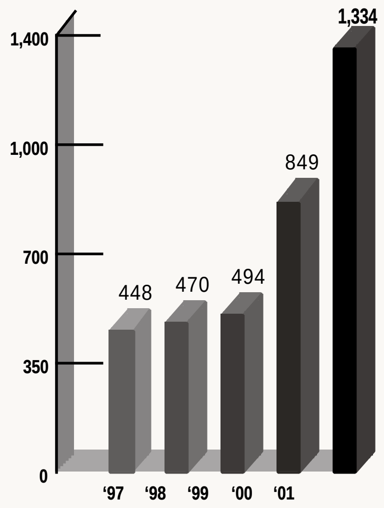
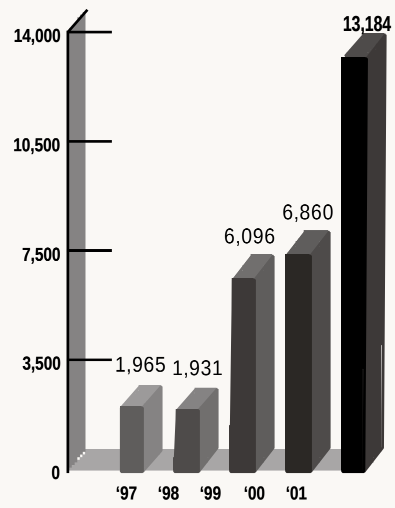
CAPITAL EXPENDITURES FOR EXPLORATION AND DEVELOPMENT
($ MILLIONS)



TOTAL ASSETS
($ MILLIONS)



SELECTED ELEVEN-YEAR FINANCIAL DATA

		1991	1992	1993	1994
OPERATING RESULTS (IN MILLIONS, EXCEPT PER SHARE DATA)					
Revenues (net of royalties):					
Oil sales	$	351	392	391	394
Gas sales	$	73	131	189	171
Natural gas liquids sales	$	5	8	13	13
Other revenue	$	19	13	31	16
Total revenues	$	448	544	624	594
Production and operating expenses	$	181	216	245	238
Depreciation, depletion and amortization of property and equipment	$	103	150	174	155
Amortization of goodwill (1)	$	–	–	–	–
General and administrative expenses	$	37	43	50	45
Expenses related to mergers	$	–	–	11	7
Interest expense (2)	$	46	57	47	33
Effects of changes in foreign currency exchange rates	$	–	–	–	–
Change in fair value of financial instruments	$	–	–	–	–
Reduction of carrying value of oil and gas properties	$	238	66	216	29
Income tax expense (benefit)	$	(52)	1	(65)	33
Total expenses	$	553	533	678	540
Net earnings (loss) before minority interest, extraordinary item and cumulative effect of change in accounting principle (3)	$	(105)	11	(54)	54
Net earnings (loss)	$	(105)	11	(55)	54
Preferred stock dividends	$	2	6	7	11
Net earnings (loss) to common shareholders	$	(107)	5	(62)	43
Net earnings (loss) per common share - basic	$	(3.66)	0.14	(1.27)	0.84
Net earnings (loss) per common share - diluted	$	(3.66)	0.13	(1.27)	0.84
Cash margin (4)	$	171	220	270	276
Weighted average shares outstanding - basic		29	39	49	51
Weighted average shares outstanding - diluted		29	42	49	54
BALANCE SHEET DATA (IN MILLIONS)					
Total assets	$	885	1,464	1,336	1,475
Debentures exchangeable into shares of ChevronTexaco Corporation common stock (5)	$	–	–	–	–
Other long-term debt (6)	$	473	571	508	457
Deferred income taxes	$	42	52	–	30
Stockholders' equity	$	203	503	472	688
Common shares outstanding		30	48	49	52

(1) Amortization of goodwill in 1999, 2000 and 2001 resulted from Devon's 1999 acquisition of PennzEnergy. Effective January 1, 2002, goodwill will no longer be amortized.
(2) Includes distributions on preferred securities of subsidiary trust of $5, $10, $10 and $7 million in 1996, 1997, 1998 and 1999, respectively.
(3) Before minority interest in Monterrey Resources, Inc. of ($1) and ($5) million in 1996 and 1997, respectively: extraordinary item of ($6) and ($4) million in 1996 and 1999, respectively; and the cumulative effect of change in accounting principle of ($1) and $49 million in 1993 and 2001, respectively.
(4) Revenues less cash expenses.
(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 1999 acquisition of PennzEnergy.
(6) Includes preferred securities of subsidiary trust of $149 million in years 1996, 1997 and 1998.
NM Not a meaningful number.

1995	1996	1997	1998	1999	2000	2001	5-YEAR GROWTH RATE	10-YEAR GROWTH RATE
464	584	555	310	561	1,079	958	10%	11%
162	221	375	347	628	1,485	1,890	54%	39%
15	29	36	25	68	154	132	35%	39%
37	36	48	24	21	66	95	21%	18%
678	870	1,014	706	1,278	2,784	3,075	29%	21%
248	297	317	275	378	597	731	20%	15%
171	192	286	243	406	693	876	36%	24%
–	–	–	–	16	41	34	NM	NM
43	47	53	45	81	93	111	19%	12%
–	–	–	13	17	60	1	NM	NM
41	54	51	53	116	155	220	32%	17%
–	–	6	16	(13)	3	13	NM	NM
–	–	–	–	–	–	2	NM	NM
97	33	641	423	476	–	1,003	98%	16%
23	89	(127)	(126)	(49)	412	30	(20%)	NM
623	712	1,227	942	1,428	2,054	3,021	34%	19%
55	158	(213)	(236)	(150)	730	54	(19%)	NM
55	151	(218)	(236)	(154)	730	103	(7%)	NM
15	47	12	–	4	10	10	(27%)	18%
40	104	(230)	(236)	(158)	720	93	(2%)	NM
0.76	1.97	(3.35)	(3.32)	(1.68)	5.66	0.73	(18%)	NM
0.76	1.92	(3.35)	(3.32)	(1.68)	5.50	0.72	(18%)	NM
339	442	557	324	663	1,748	1,941	34%	28%
52	53	69	71	94	127	128	19%	16%
53	56	75	77	99	132	130	18%	16%
1,639	2,242	1,965	1,931	6,096	6,860	13,184	43%	31%
–	–	–	–	760	760	649	NM	NM
565	511	576	885	1,656	1,289	5,940	63%	29%
48	136	43	–	324	627	2,142	74%	48%
739	1,160	1,007	750	2,521	3,277	3,259	23%	32%
52	63	71	71	126	129	126	15%	15%

MANAGEMENT'S DISCUSSION & ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

OVERVIEW

In August and September 2001, Devon announced two major acquisitions that eventually would almost double our total proved reserves to over two billion Boe. On August 13, 2001, Devon announced an agreement to acquire Mitchell Energy & Development Corp. ("Mitchell"). The terms of this agreement called for Devon to issue approximately 30 million shares of Devon common stock and to pay $1.6 billion in cash to the Mitchell stockholders. Although the merger agreement was signed in August 2001, the transaction did not close until January 24, 2002. Therefore, this acquisition did not affect our 2001 reported results.

Following the Mitchell announcement, 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. Therefore, Devon's results include Anderson's results for the last 2 1/2 months of the year.

Devon entered into long-term debt agreements in October 2001 that totaled $6 billion. The purpose of this debt was to fund the cash portions of these two acquisitions, to pay related transaction costs and retire certain long-term debt assumed from Mitchell and Anderson. As part of this $6 billion total, Devon issued $3 billion of notes and debentures 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. At December 31, 2001, $1 billion of this facility was borrowed. Following the close of the Mitchell transaction, the $3 billion facility was fully borrowed. Principal payments due on this debt are $0.2 billion in October 2004, $1.2 billion in 2005 and $1.6 billion in 2006. The 2005 and 2006 payments are to be split equally in payments due in April and October of those years. The interest rate on this debt at December 31, 2001 was 2.9%.

The Mitchell and Anderson acquisitions followed two other significant acquisitions by Devon in the two preceding years. In August 2000, we merged with Santa Fe Snyder Corporation. In August 1999 we acquired PennzEnergy Company. These two transactions combined added approximately 782 million Boe to our proved reserves. By comparison, Devon's total consolidated proved reserves at the end of 1998 were 299 million Boe.

In addition to the mergers and acquisitions, exploration and development efforts have also been significant contributors to our growth. In 1999, before the merger with Santa Fe Snyder, Devon spent approximately $0.3 billion for exploration, drilling and development. These costs included drilling 678 wells, of which 636 were completed as producers. In 2000, Devon and Santa Fe Snyder combined spent $0.9 billion for exploration, drilling and development. These costs included drilling 1,328 wells, of which 1,261 were completed as producers. In 2001, Devon spent $2.9 billion for exploration, drilling and development. These costs included drilling 1,545 wells, of which 1,444 were completed as producers. We also acquired $1.4 billion of unproved leasehold in the Anderson acquisition.

Our acquisitions of Anderson in 2001 and PennzEnergy in 1999 were accounted for using the purchase method of accounting for business combinations. In May 1999, prior to its merger with Devon, Santa Fe Snyder's predecessor acquired Snyder Oil Company. This acquisition was also accounted for using the purchase method. Accordingly, these acquisitions did not affect our reported results until after the closing dates of the acquisitions. Our merger with Santa Fe Snyder was accounted for under the pooling-of-interests method of accounting for business combinations. Accordingly, Devon's prior years' results have been restated. The restated results include those of Santa Fe Snyder for all years presented. Thus, the three-year comparisons of various production, revenue and expense items presented later in this section are shown as if Devon and Santa Fe Snyder had been combined for all such periods. Although this is consistent with the financial presentation of the merger, it distorts the fact that the transaction did not actually affect Devon's operations prior to August 2000.

The following statistics reflect the effects that our mergers and acquisitions and our drilling and development activities have had on operations during the last three years. This data compares Devon's 2001 results to those of 1999 for Devon only, without Santa Fe Snyder. This comparison yields the following:

- Combined oil, gas and NGL production increased 82 million Boe, or 155%.
- The average combined sales price of oil, gas and NGLs increased by $8.43 per Boe, or 62%.
- Total revenues increased $2.3 billion, or 319%.
- Net cash provided by operating activities increased $1.7 billion, or 816%. Cash margin increased $1.5 billion, or 395%.

During 2001, Devon marked its 13th anniversary as a public company. We have consistently increased production over this 13-year period. However, volatility in oil and gas 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 a number of factors beyond our control such as regional and worldwide economic growth and weather. Our future earnings and cash flows will continue to depend on market conditions.

Like all oil and gas 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 production company depletes part of its asset base with each unit of oil or gas it produces. Historically, Devon has been able to overcome this natural decline by adding, through drilling and acquisitions, more reserves than it produces. Devon's future growth, if any, will depend on its ability to continue to add reserves in excess of production.

Oil and gas prices are influenced by many factors outside of our control. Devon's management has focused its efforts, therefore, on increasing oil and gas reserves and production and controlling expenses. Over our 13-year history as a public company, we have 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

The following discussion of Devon's results of operations from 1999 through 2001 includes restatements required by the 2000 merger with Santa Fe Snyder. This was accounted for using the pooling-of-interests method.

Our total revenues have risen from $1.3 billion in 1999 to $3.1 billion in 2001. In each of these three years, oil, gas and NGL sales accounted for over 96% of total revenues.

Changes in oil, gas and NGL production, prices and revenues from 1999 to 2001 are shown in the following tables. (Unless otherwise stated, all dollar amounts are expressed in U.S. dollars.)

	TOTAL YEAR ENDED DECEMBER 31,					
		2001	2001 vs 2000	2000	2000 vs 1999	1999
PRODUCTION						
Oil (MMBbls)		44	+2%	43	+34%	32
Gas (Bcf)		498	+17%	426	+40%	304
NGLs (MMBbls)		8	+14%	7	+40%	5
Oil, gas and NGLs (MMBoe)		135	+12%	121	+38%	88
REVENUES						
Per Unit of Production:						
Oil (per Bbl)	$	21.57	-15%	25.35	+43%	17.67
Gas (per Mcf)	$	3.80	+9%	3.49	+69%	2.06
NGLs (per Bbl)	$	16.98	-19%	20.87	+57%	13.30
Oil, gas and NGLs (per Boe)	$	22.05	-2%	22.47	+57%	14.35
Absolute (in millions):						
Oil	$	958	-11%	1,079	+92%	561
Gas	$	1,890	+27%	1,485	+136%	628
NGLs	$	132	-14%	154	+126%	68
Oil, gas and NGLs	$	2,980	+10%	2,718	+116%	1,257

	DOMESTIC YEAR ENDED DECEMBER 31,					
		2001	2001 vs 2000	2000	2000 vs 1999	1999
PRODUCTION						
Oil (MMBbls)		26	-10%	29	+61%	18
Gas (Bcf)		376	+6%	355	+61%	221
NGLs (MMBbls)		6	–	6	+50%	4
Oil, gas and NGLs (MMBoe)		95	+1%	94	+59%	59
REVENUES						
Per Unit of Production:						
Oil (per Bbl)	$	22.36	-12%	25.45	+37%	18.64
Gas (per Mcf)	$	4.17	+14%	3.67	+62%	2.27
NGLs (per Bbl)	$	17.15	-16%	20.30	+55%	13.11
Oil, gas and NGLs (per Boe)	$	23.80	+4%	22.95	+52%	15.10
Absolute (in millions):						
Oil	$	586	-19%	727	+119%	332
Gas	$	1,571	+20%	1,305	+160%	502
NGLs	$	103	-24%	136	+134%	58
Oil, gas and NGLs	$	2,260	+4%	2,168	+143%	892

	CANADA YEAR ENDED DECEMBER 31,				
	2001	2001 vs 2000	2000	2000 vs 1999	1999
PRODUCTION					
Oil (MMBbls)	8	+60%	5	–	5
Gas (Bcf)	113	+82%	62	-16%	74
NGLs (MMBbls)	2	+100%	1	–	1
Oil, gas and NGLs (MMBoe)	29	+81%	16	-11%	18
REVENUES					
Per Unit of Production:					
Oil (per Bbl)	$ 17.84	-27%	24.46	+58%	15.51
Gas (per Mcf)	$ 2.73	+1%	2.71	+75%	1.55
NGLs (per Bbl)	$ 16.43	-38%	26.51	+84%	14.39
Oil, gas and NGLs (per Boe)	$ 16.80	-12%	19.18	+70%	11.27
Absolute (in millions):					
Oil	$ 146	+26%	116	+45%	80
Gas	$ 307	+82%	169	+48%	114
NGLs	$ 28	+56%	18	+80%	10
Oil, gas and NGLs	$ 481	+59%	303	+49%	204

	INTERNATIONAL YEAR ENDED DECEMBER 31,				
	2001	2001 vs 2000	2000	2000 vs 1999	1999
PRODUCTION					
Oil (MMBbls)	10	+11%	9	–	9
Gas (Bcf)	9	–	9	–	9
NGLs (MMBbls)	–	NM	–	NM	–
Oil, gas and NGLs (MMBoe)	11	–	11	–	11
REVENUES					
Per Unit of Production:					
Oil (per Bbl)	$ 22.57	-11%	25.48	+50%	16.96
Gas (per Mcf)	$ 1.41	+7%	1.32	+6%	1.24
NGLs (per Bbl)	$ 16.15	-24%	21.19	+6%	20.00
Oil, gas and NGLs (per Boe)	$ 20.76	-10%	23.08	+49%	15.50
Absolute (in millions):					
Oil	$ 226	-4%	236	+58%	149
Gas	$ 12	+9%	11	-8%	12
NGLs	$ 1	NM	–	NM	–
Oil, gas and NGLs	$ 239	-3%	247	+53%	161

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

	WITH HEDGES			**WITHOUT HEDGES**		
	2001	**2000**	**1999**	**2001**	**2000**	**1999**
Oil (per Bbl)	$ 21.57	25.35	17.67	$ 21.41	26.20	17.75
Gas (per Mcf)	$ 3.80	3.49	2.06	$ 3.94	3.57	2.07
NGLs (per Bbl)	$ 16.98	20.87	13.30	$ 16.98	20.87	13.30
Oil, gas and NGLs (per Boe)	$ 22.05	22.47	14.35	$ 22.53	23.05	14.42

OIL REVENUES ***2001 vs. 2000*** Oil revenues decreased $121 million in 2001. Of this total decrease, $167 million was due to a $3.78 per barrel decrease in the average price of oil in 2001. An increase in production of one million barrels caused oil revenues to increase by $46 million. The October 2001 Anderson merger accounted for three million barrels of 2001 production. Oil production from Devon's other properties declined two million barrels. This reduction was primarily the result of domestic and international properties that were sold prior to 2001. Production from these properties was included in 2000 prior to the sales.

2000 vs. 1999 Oil revenues increased $518 million in 2000. Of this total increase, $327 million was due to a $7.68 per barrel increase in the average price of oil in 2000. An increase in production of 11 million barrels caused the remaining $191 million of increased revenues. The 1999 PennzEnergy merger accounted for seven million barrels of the 11 million barrel increase. The year 2000 included 12 months of production from the properties acquired in the PennzEnergy merger. The 1999 results included production for only 4 1/2 months following the August 17, 1999 merger closing. The remaining four million barrel increase in 2000's production was caused by drilling activity and other acquisitions. This was offset in part by property dispositions and natural declines.

GAS REVENUES ***2001 vs. 2000*** Gas revenues increased $405 million in 2001. Of this total increase, $249 million was due to a 72 Bcf increase in production in 2001. The October 2001 Anderson acquisition accounted for 51 Bcf of the increase. Production from Devon's domestic properties increased 21 Bcf. This was due primarily to drilling and development in Devon's coalbed methane properties and to 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 $156 million of increased gas revenues.

2000 vs. 1999 Gas revenues increased $857 million in 2000. Of this total increase, $605 million was due to a $1.43 per Mcf increase in the 2000 average gas price. A 122 Bcf increase in production added the remaining $252 million increase in gas revenues. The PennzEnergy merger accounted for 89 Bcf of the 122 Bcf increase in production. Production from Devon's other domestic properties increased 45 Bcf. This was due primarily to additional development and acquisitions, net of natural declines and dispositions. Canadian gas production decreased 12 Bcf, or 16%, in 2000. Natural decline, increased royalty rates and dispositions of certain properties contributed to this production decline.

NGL REVENUES ***2001 vs. 2000*** NGL revenues decreased $22 million in 2001. A decrease in 2001's average price of $3.89 per barrel caused NGL revenues to decrease $30 million. This was partially offset by an $8 million increase related to a production increase of one million barrels. The October 2001 Anderson acquisition accounted for all of the increase.

2000 vs. 1999 NGL revenues increased $86 million in 2000. An increase in 2000's average price of $7.57 per barrel caused $56 million of the increase. A production increase of two million barrels caused the remaining $30 million increase. The 1999 PennzEnergy merger accounted for the entire increase in NGL production in 2000.

OTHER REVENUES ***2001 vs. 2000*** Other revenues increased $29 million, or 44% in 2001. Other revenues in 2001 included a $30 million gain from the settlement of a foreign exchange forward purchase contract entered into by Devon. The forward purchase contract related to the funding of the Anderson acquisition.

2000 vs. 1999 Other revenues increased $45 million, or 214%, in 2000. Increases in third party gas processing income of $17 million and interest income of $5 million were the primary reasons for the increase. Additionally, the 2000 period included $18 million of dividend income from seven million shares of ChevronTexaco Corporation common stock owned by Devon. This stock was acquired in the 1999 PennzEnergy merger. The 1999 period included only $7 million of dividend income on these same shares because Devon did not acquire the shares until August 1999.

EXPENSES The details of the changes in pre-tax expenses between 1999 and 2001 are shown in the table below.

	YEAR ENDED DECEMBER 31,				
	2001	2001 vs 2000	2000	2000 vs 1999	1999
Absolute (in millions):					
Production and operating expenses:					
Lease operating expenses	$ 531	+20%	441	+47%	299
Transportation costs	83	+57%	53	+56%	34
Production taxes	117	+14%	103	+129%	45
Depreciation, depletion and amortization of oil and gas properties	838	+26%	663	+70%	390
Amortization of goodwill	34	-17%	41	+156%	16
Subtotal	1,603	+23%	1,301	+66%	784
Depreciation and amortization of non-oil and gas properties	38	+27%	30	+88%	16
General and administrative expenses	111	+19%	93	+15%	81
Expenses related to mergers	1	-98%	60	+253%	17
Interest expense	220	+42%	155	+42%	109
Effects of changes in foreign currency exchange rates	13	+333%	3	-123%	(13)
Change in fair value of financial instruments	2	NM	–	NM	–
Distributions on preferred securities of subsidiary trust	–	NM	–	-100%	7
Reduction of carrying value of oil and gas properties	1,003	NM	–	-100%	476
Total	$ 2,991	+82%	1,642	+11%	1,477
Per Boe:					
Production and operating expenses:					
Lease operating expenses	$ 3.93	+8%	3.65	+7%	3.41
Transportation costs	0.61	+39%	0.44	+13%	0.39
Production taxes	0.87	+2%	0.85	+67%	0.51
Depreciation, depletion and amortization of oil and gas properties	6.20	+13%	5.48	+23%	4.46
Amortization of goodwill	0.25	-26%	0.34	+89%	0.18
Subtotal	11.86	+10%	10.76	+20%	8.95
Depreciation and amortization of non-oil and gas properties (1)	0.28	+12%	0.25	+32%	0.19
General and administrative expenses (1)	0.82	+6%	0.77	-16%	0.92
Expenses related to mergers (1)	0.01	-98%	0.50	+163%	0.19
Interest expense (1)	1.63	+28%	1.27	+2%	1.25
Effects of changes in foreign currency exchange rates (1)	0.09	+350%	0.02	NM	(0.15)
Change in fair value of financial instruments (1)	0.02	NM	–	NM	–
Distributions on preferred securities of subsidiary trust (1)	–	NM	–	-100%	0.08
Reduction of carrying value of oil and gas properties (1)	7.43	NM	–	-100%	5.44
Total	$ 22.14	+63%	13.57	-20%	16.87

(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.

PRODUCTION AND OPERATING EXPENSES The details of the changes in production and operating expenses between 1999 and 2001 are shown in the table below.

	YEAR ENDED DECEMBER 31,				
	2001	2001 vs 2000	2000	2000 vs 1999	1999
Absolute (in millions):					
Recurring lease operating expenses	$ 513	+21%	423	+45%	291
Well workover expenses	18	+0%	18	+125%	8
Transportation costs	83	+57%	53	+56%	34
Production taxes	117	+14%	103	+129%	45
Total production and operating expenses	$ 731	+22%	597	+58%	378
Per Boe:					
Recurring lease operating expenses	$ 3.79	+8%	3.50	+5%	3.32
Well workover expenses	0.14	-7%	0.15	+67%	0.09
Transportation costs	0.61	+39%	0.44	+13%	0.39
Production taxes	0.87	+2%	0.85	+67%	0.51
Total production and operating expenses	$ 5.41	+10%	4.94	+15%	4.31

2001 vs. 2000 Recurring lease operating expenses increased $90 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 as well as increased production.

Transportation costs represent those costs paid directly to third-party providers to transport oil and gas production sold downstream from the wellhead. Transportation costs increased $30 million, or 57% in 2001. Of this increase, $12 million related to the Anderson acquisition. The remainder of the increase was primarily due to an increase in coalbed methane gas production and increases in transportation rates.

The majority of Devon's production taxes are assessed on our onshore domestic properties. In the U.S., most of the production taxes are based on a fixed percentage of revenues. Therefore, the 4% increase in domestic oil, gas and NGL revenues was the primary cause of a 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 change in domestic revenues occurred in the western U.S. The western U.S. has higher production tax rates than most other domestic areas.

2000 vs. 1999 Recurring lease operating expenses increased $132 million in 2000. The 1999 PennzEnergy merger accounted for $92 million of the increase in expenses. Additionally, $19 million of costs were added by other 1999 and 2000 acquisitions. Other than the added costs from these acquisitions, our recurring costs increased $21 million, or 7%, in 2000. This increase was primarily caused by increased production and higher ad valorem taxes and fuel costs.

Transportation costs increased $19 million in 2000. This was primarily due to increased production.

As previously stated, most of our U.S. production taxes are based on a fixed percentage of revenues. Therefore, the 143% increase in domestic oil, gas and NGL revenues was the primary cause of a 136% increase in domestic production taxes.

DEPRECIATION, DEPLETION AND AMORTIZATION (“DD&A”) Our largest recurring non-cash expense is 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.

2001 vs. 2000 Oil and gas property related DD&A increased $175 million in 2001. Of this total increase, $77 million was due to the 12% increase in oil, gas and NGL production in 2001. The remaining $98 million increase was due to an increase in the consolidated DD&A rate. This rate increased from $5.48 per Boe in 2000 to $6.20 per Boe in 2001.

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

2000 vs. 1999 Oil and gas property related DD&A increased $273 million in 2000. Of this total increase, $149 million was due to the 38% increase in oil, gas and NGL production in 2000. The remaining $124 million increase was due to an increase in our consolidated DD&A rate. The consolidated DD&A rate increased from $4.46 per Boe in 1999 to $5.48 per Boe in 2000.

Non-oil and gas property DD&A increased $14 million in 2000 compared to 1999. Depreciation of the non-oil and gas properties acquired in the PennzEnergy and Snyder mergers contributed to the increase. Depreciation of Devon's Wyoming gas pipeline and gathering systems also contributed to the increase.

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 in properties 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. See the following table for a summary of G&A expenses by component.

	YEAR ENDED DECEMBER 31,				
	2001	2001 vs 2000	2000	2000 vs 1999	1999
			(IN MILLIONS)		
Gross G&A	**$ 245**	+19%	206	+36%	151
Capitalized G&A	**(77)**	+24%	(62)	+114%	(29)
Reimbursed G&A	**(57)**	+12%	(51)	+24%	(41)
Net G&A	**$ 111**	+19%	93	+15%	81

2001 vs. 2000 Net G&A increased $18 million in 2001. Gross G&A increased $39 million. This was primarily due to additional costs incurred as a result of the Anderson acquisition and additional personnel related costs. G&A was reduced $15 million in 2001 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.

2000 vs. 1999 Net G&A increased $12 million in 2000. Gross G&A increased $55 million primarily due to additional costs incurred as a result of the 1999 PennzEnergy and Snyder mergers. G&A was reduced $33 million due to an increase in the amount capitalized. G&A was also reduced $10 million by an increase in the amount of reimbursements on operated properties. The increase in capitalized and reimbursed G&A was primarily related to the 1999 PennzEnergy and Snyder mergers.

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 consisted primarily of 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 requires such costs to be expensed and not capitalized as costs of the transaction.

Approximately $17 million of expenses were incurred by Santa Fe Snyder in 1999 related to the Snyder merger. These costs included $14 million related to compensation plans and other benefits, and $2 million of severance and relocation costs. The $17 million of costs related to the operations and employees of the former Santa Fe Energy Resources, Inc., not those of the former Snyder Oil Corporation.

INTEREST EXPENSE ***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 in October 2001 to acquire Anderson.

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. Other items include facility and agency fees, amortization of costs and other miscellaneous items. The increase in other items was primarily related to an increase in accretion of discounts and a $7 million loss related to the early retirement of debt.

The increase in accretion of debt discounts in 2001 was a result of the adoption of Statement of Financial Accounting Standards No. 133 (“SFAS No. 133”) effective January 1, 2001. Devon’s debentures that are exchangeable into shares of ChevronTexaco Corporation 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 Corporation 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.

2000 vs. 1999 Interest expense increased $46 million in 2000. Of this increase, $54 million was due to an increase in the average debt balance outstanding from $1.5 billion in 1999 to $2.3 billion in 2000. The increase in average debt outstanding in 2000 was attributable to the long-term debt assumed in the Snyder and PennzEnergy mergers on May 5, 1999 and August 17, 1999, respectively.

The average interest rate on outstanding debt decreased from 7% in 1999 to 6.7% in 2000. This rate decrease caused interest expense to decrease $5 million in 2000. Other items included in interest expense that are not related to the debt balance outstanding were $3 million lower in 2000 compared to 1999.

EFFECTS OF CHANGES IN FOREIGN CURRENCY EXCHANGE RATES ***2001 vs. 2000*** As a result of the Anderson acquisition, our Canadian subsidiary, Devon Canada Corporation, assumed certain 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 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 drop in the Canadian-to-U.S. dollar exchange rate from $0.642 at October 15, 2001 to $0.628 at December 31, 2001 resulted in an $11 million loss. Additionally, the devaluation of the Argentine peso resulted in a $2 million loss in 2001.

Until mid-January 2000, Northstar 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.

2000 vs. 1999 The rate of converting Canadian dollars to U.S. dollars increased from $0.6535 at the end of 1998 to $0.6929 at the end of 1999. The balance of Northstar's U.S. dollar denominated notes remained constant at $225 million throughout 1999. The higher conversion rate on the $225 million of debt reduced the Canadian dollar equivalent of debt recorded by Northstar at the end of 1999. Therefore, a $13 million reduction to expenses was recorded in 1999.

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 lower of cost or fair value of unproved properties. The ceiling is imposed 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.

During 2001 and 1999, we reduced the carrying value of our oil and gas properties by $916 and $476 million, respectively, due to the full cost ceiling limitations. The after-tax effect of these reductions in 2001 and 1999 were $556 million and $310 million, respectively. The following table summarizes these reductions by country.

	YEAR ENDED DECEMBER 31,			
	2001		1999	
	GROSS	NET OF TAXES	GROSS	NET OF TAXES
	(IN MILLIONS)			
United States	$ 449	281	464	302
Canada	434	252	–	–
Egypt	33	23	–	–
China	–	–	12	8
Total	$ 916	556	476	310

The 2001 domestic and Canadian reductions were 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 our 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 indicative of the true fair value of the reserves. 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 year-end 2001 prices used to calculate the ceiling. The reduction in Egypt was the result of high finding and development costs and negative revisions to proved reserves.

The 1999 domestic reduction was primarily the result of lower prices. The oil and gas properties added from the Snyder acquisition were recorded at fair values that were based on expected future oil and gas prices higher than the quarterly prices used to calculate the ceiling. The reduction in China was the result of high finding and development costs.

Additionally, during 2001, we elected to discontinue operations in Thailand, Malaysia, Qatar and on certain properties in Brazil. After meeting the drilling and capital commitments on these properties, we determined that these properties did not meet the company’s internal criteria to justify further investment. Accordingly, we recorded an $87 million charge associated with the impairment of these properties. The after-tax effect of this reduction was $69 million.

INCOME TAXES ***2001 vs. 2000*** Our 2001 and 2000 effective financial tax expense rates were 36% each year. 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. This was offset in part by the recognition of a benefit from the disposition of our assets in Venezuela.

2000 vs. 1999 Our 2000 effective financial tax expense rate was 36%. This rate was higher than the statutory federal tax rate of 35% as discussed previously. The 1999 effective financial tax benefit rate was 25%. This rate was lower than the statutory federal tax rate of 35% due to the effect of goodwill amortization that was not deductible for income tax purposes and the effect of foreign income taxes.

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 $49.5 million gain. This gain was related to the fair value of derivatives that do not qualify as hedges. This gain included $46.2 million related to the option embedded in the debentures that are exchangeable into shares of ChevronTexaco Corporation 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 $5.3 billion was spent in 2001 for capital expenditures. Of that amount $5.2 billion was related to the acquisition, drilling or development of oil and gas properties. These amounts compare to 2000 total expenditures of $1.3 billion ($1.2 billion of which was related to oil and gas properties) and 1999 total expenditures of $0.9 billion ($0.8 billion of which was related to oil and gas properties).

OTHER CASH USES We paid common stock dividends of $25 million, $22 million and $13 million in 2001, 2000 and 1999, respectively. We also paid $10 million of preferred stock dividends in 2001 and 2000 and $4 million in the last 4 1/2 months of 1999 following the PennzEnergy merger.

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 common stock in 2001 under an odd-lot repurchase program. Pursuant to this program, Devon purchased and retired 232,000 shares of our common stock for a total cost of $14 million, or $57.40 per share.

CAPITAL RESOURCES AND LIQUIDITY Our 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 will be sales of oil and gas properties.

Our operating cash flow is sensitive to many variables. The most volatile of these variables 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 growth, weather and other substantially variable factors influence market conditions. These factors are beyond our control and are difficult to predict.

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

	FIXED-PRICE PHYSICAL DELIVERY CONTRACTS	PRICE SWAP CONTRACTS	PRICE COLLARS	TOTAL
Oil production (MMBbls)				
2002	2	10	7	19
Natural gas production (Bcf)				
2002	53	88	162	303
2003	26	36	126	188
2004	19	2	–	21

For the years 2005 through 2011, Devon has fixed-price physical delivery contracts covering natural gas production ranging from 13 Bcf to 19 Bcf per year. We also have Canadian gas volumes subject to fixed-price contracts in the years from 2012 through 2016, but the yearly volumes are less than one Bcf.

By removing the price volatility from the above volumes of oil and natural gas production, we have mitigated, but not eliminated, the potential negative effect of declining prices on our operating cash flow. 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 2001, we announced that our capital expenditure budget for the year 2002 was approximately $1.5 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 our control. Therefore, if oil and natural gas prices decline below acceptable levels, Devon could choose to defer a portion of these planned 2002 capital expenditures.

Other sources of liquidity are our revolving lines of credit. As of December 31, 2001, these credit lines totaled $1.1 billion, of which $884 million was available as of the end of 2001. The majority of the revolving credit lines consist of 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. We may borrow funds under the Tranche B facility until August 12, 2002 (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. Debt borrowed under the Tranche B facility matures two years and one day following the end of the Tranche B Revolving Period. On December 31, 2001, there was $50 million of debt outstanding under Tranche A of the $725 million U.S. Facility.

We may borrow funds under the $275 million Canadian Facility until August 12, 2002 (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 45 and 90 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 semi-annual 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, 2001, there were no borrowings outstanding under the Canadian Facility.

Under the terms of the revolving credit facilities, we have the right to reallocate up to $100 million of the unused Tranche B facility maximum credit amount to the Canadian Facility. Conversely, we also have the right to reallocate up to $100 million of unused Canadian Facility maximum credit amount to the Tranche B facility.

Amounts borrowed under the revolving 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 our debt rating. Based upon our current debt rating, we can borrow under the revolving credit facilities at a rate of between 45.0 and 47.5 basis points above LIBOR, and 45.0 basis points above the Bankers' Acceptance rate. Devon had $50 million of debt outstanding under our revolving credit facilities at December 31, 2001, at an average interest rate of 4.8%.

We also have access to short-term credit under our commercial paper program. Total borrowings under the U.S. Facility and the commercial paper program may not exceed $725 million. Commercial paper debt generally has a maturity of between seven to 90 days, although it can have a maturity of up to 365 days. Devon had $75 million of commercial paper debt outstanding at December 31, 2001, at an interest rate of 3.5%.

Devon's access to funds from our revolving 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 under certain conditions. Such conditions could include any condition or event that 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. Devon's $1 billion revolving credit facilities and our $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. However, the obligation of the banks to fund the revolving credit facilities is not expressly conditioned on the absence of a material adverse effect.

A portion of the 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, which was fully borrowed upon the closing of the Mitchell acquisition on January 24, 2002, will mature as follows:

	(MILLIONS)
October 15, 2004	$ 232
April 15, 2005	$ 600
October 15, 2005	$ 600
April 15, 2006	$ 800
October 15, 2006	$ 800
	$ 3,032

Borrowings under this $3 billion facility may be made under various rate options elected by Devon, including a rate based on LIBOR plus a margin. Through June 17, 2002, this margin is fixed at 100 basis points. Thereafter, the margin will be based on our debt rating. Based on our current debt rating, the margin after June 17, 2002, would be 100 basis points. Following the close of the Mitchell acquisition, we had $3 billion borrowed under this facility as of January 31, 2002, at an interest rate of 2.8%.

The terms of this $3 billion facility also provide that voluntary prepayments of the debt may be applied, at Devon's option, to the earliest scheduled maturities first. For example, if we were to prepay a portion of the $3 billion of debt with proceeds from property sales or other cash sources, the amount of the prepayment would reduce, if so elected by Devon, the amounts otherwise due first in 2004, then 2005 and finally 2006.

Devon's $1 billion revolving credit facilities and our $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 70% through June 30, 2002, and no more than 65% thereafter. 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. Per 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 non-cash financial writedowns such as full cost ceiling property impairments or goodwill impairments.

As of December 31, 2001, Devon's ratio of total funded debt to total capitalization, as defined in its credit agreements, was 60.5%. On a pro forma basis, assuming the Mitchell acquisition had closed on December 31, 2001, the ratio was 59.5%.

We intend to divest approximately $1 billion of oil and gas properties in 2002. We are currently in the early stages of the property divestiture activities. Although we believe we will be able to generate the desired amount of cash from these divestitures, it is possible that market conditions could result in the properties being sold for less than originally believed. If all the properties currently identified are sold, and the proceeds are less than the stated goal of $1 billion, Devon's alternatives would depend on the circumstances, including the actual amount of cash that is raised from the sales and the overall market for property sales at the time. Failure to reduce our indebtedness to the extent desired through these property divestitures or other cash sources could result in unfavorable actions by the various credit rating agencies.

We receive debt ratings from the major ratings agencies in the United States. In determining our debt ratings, the agencies consider a number of items. These include, but are not limited to, debt levels, planned asset sales, near-term and long-term production growth opportunities, capital allocation challenges and commodity pricing levels.

Devon's current debt ratings are BBB with a stable outlook by Standard & Poor's and Baa2 with a negative outlook by Moody's. There are no "rating triggers" in any of our contractual obligations that would accelerate scheduled maturities should our debt ratings fall below a specified level. Certain of Devon's agreements related to its oil and natural gas hedges do contain provisions that could require Devon to provide cash collateral in situations where Devon's liability under the hedge is above a certain dollar threshold, and where Devon's debt rating is below investment grade (BBB- or Baa3). However, our liability under these agreements would only exceed the maximum level in circumstances where the market prices for oil or natural gas were rising. It is unlikely that our 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, our cost of borrowing under the $1 billion revolving credit facilities and the $3 billion term loan credit facility is predicated on our corporate debt rating. Therefore, even though a ratings downgrade would not accelerate scheduled maturities, it would adversely impact the interest rate on our variable rate debt. Under the terms of the $1 billion revolving credit facilities and the $3 billion term loan credit facility, a one notch downgrade would increase our borrowing rates by 22.5 basis points and 25 basis points, respectively. A ratings downgrade could also adversely impact our ability to economically access future debt markets. As of January 31, 2002, we are not aware of any potential ratings downgrades being contemplated by the rating agencies.

A summary of Devon's contractual obligations as of December 31, 2001, is provided in the following table.

	PAYMENTS DUE BY YEAR						
	2002	2003	2004	2005	2006	AFTER 2006	TOTAL
	(IN MILLIONS)						
Long-term debt	$ –	–	358	775	689	4,886	6,708
Operating leases	21	20	16	14	11	14	96
Drilling obligations	170	17	–	–	–	–	187
Firm transportation agreements	93	82	65	49	42	219	550
Total	$ 284	119	439	838	742	5,119	7,541

Firm transportation agreements represent "ship or pay" arrangements whereby Devon has committed to ship certain volumes of gas for a fixed transportation fee. Devon has entered into these agreements to ensure that Devon can get its gas production to market. Devon expects to have sufficient volumes to ship to satisfy the firm transportation agreements, so that Devon will be receiving equivalent value for the firm transportation payments that it will make.

The above table does not include $89 million of letters of credit that have been issued by commercial banks on Devon's behalf. If funded, the letters of credit would become borrowings under our revolving credit facility. Most of these letters of credit have been granted by financial institutions to support our Canadian drilling commitments. The $6.7 billion of long-term debt shown in the table excludes $119 million of discounts included in the December 31, 2001, book balance of the debt.

CRITICAL ACCOUNTING POLICIES

In December 2001, the Securities and Exchange Commission encouraged public companies to include in their annual report information on critical accounting policies. These policies have been defined as those that are very important to the portrayal of the company's financial condition and results, and require management's most difficult, subjective or complex judgments. Below is information on what we believe are our critical accounting policies.

Full cost ceiling calculations We follow the full cost method of accounting for our oil and gas properties. The full cost method subjects companies to quarterly calculations of a "ceiling," or limitation on the amount of properties that can be capitalized on the balance sheet. If Devon's 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.

The discounted present value of our proved oil, natural gas and NGL reserves is a major component of the ceiling calculation, and represents the component that requires the most subjective judgments. Estimates of reserves are forecasts based on engineering data, projected future rates of production and the timing of future expenditures. The process of estimating oil, natural gas and NGL reserves requires substantial judgment, resulting in imprecise determinations, particularly for new discoveries. Different reserve engineers may make different estimates of reserve quantities based on the same data. Certain of Devon's reserve estimates are prepared by outside consultants, while other reserve estimates are prepared by our own employees.

The passage of time provides more qualitative information regarding estimates of reserves. Revisions are made to prior estimates to reflect updated information. In the past four years, our annual revisions to our 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 reduce previously estimated reserve quantities, it could result in a full cost property writedown. Estimates of proved reserves are also a significant component in the calculation of DD&A.

While the estimated quantities of proved reserves require substantial judgment, the associated prices of oil, natural gas and NGL reserves that are included in the discounted present value of the reserves do not require judgment. The ceiling calculation dictates that prices and costs in effect as of the last day of the period are generally held constant indefinitely. Therefore, the future net revenues associated with the estimated proved reserves are not based on Devon's assessment of future prices or costs. Rather they are based on such prices and costs in effect as of the end of each quarter when the ceiling calculation is performed. In calculating the ceiling, Devon does not adjust the end-of-period price by the effect of cash flow hedges in place.

Because the ceiling calculation dictates that prices in effect as of the last day of the applicable quarter are held constant indefinitely, 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, they can be either substantially higher or lower than Devon's long-term price forecast that is a barometer for true fair value. Therefore, oil and gas property writedowns that result from applying the full cost ceiling limitation should not be viewed as absolute indicators of a reduction of the ultimate value of the related reserves. This is because they are caused by fluctuations in price as opposed to reductions to the underlying quantities of reserves.

We 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 and a Henry Hub gas price of $2.65 per MMBtu. If oil or gas prices at the end of future quarters drop below these year-end 2001 prices, or if we reduce our estimates of proved reserve quantities, further writedowns would likely occur. Also, in January 2002, we closed our Mitchell acquisition. The oil and gas properties acquired in this transaction were recorded at their estimated fair value. The fair values were based on our estimates of future oil and gas prices, and these estimated prices were higher than the year-end 2001 market prices for oil and gas. Therefore, the Mitchell properties were recorded at amounts which would have exceeded the related full cost ceiling calculation as of the end of 2001. This increases the likelihood that Devon will incur further property writedowns of its domestic oil and gas properties.

Fair values of derivative instruments The estimated fair values of Devon's derivative instruments are recorded on our 2001 consolidated balance sheet. 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 our 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. We estimate the fair values of derivatives on a monthly basis using a discounted future cash flow technique. Devon obtains the forecasts of future NYMEX oil and gas prices from independent third parties. Many of Devon's hedges relate to regional prices other than NYMEX. Therefore, where necessary, Devon adjusts the NYMEX prices to prices at other regional delivery points using our own estimates of future differentials. The estimated future prices are compared to the prices fixed by the hedge agreements. The resulting estimated future cash inflows or outflows over the lives of the hedges are discounted using Devon's current borrowing rates under its revolving credit facilities. These pricing and discounting variables are sensitive to market volatility as well as changes in future price forecasts, 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 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 ensure 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, the accounting for goodwill has changed. In prior years, goodwill was amortized over its estimated useful life. As of 2002, goodwill with an indefinite useful life 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, we prepare estimates of oil, natural gas and NGL reserves. These estimates are based on work performed by our engineers and that of outside consultants. The judgments associated with these estimated reserves are described earlier in this section in connection with the full cost ceiling calculation.

However, there are factors involved in estimating the fair values of acquired oil, natural gas and NGL properties that require more judgment than that involved in the full cost ceiling calculation. As stated above, the full cost ceiling calculation applies 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. Our estimates of future prices are based on our own analysis of pricing trends. These estimates are based on current data obtained with regard to regional and worldwide supply and demand dynamics such as economic growth forecasts. They are also based on industry data regarding natural gas storage availability, drilling rig activity, changes in delivery capacity and trends in regional pricing differentials. Future price forecasts from independent third parties are also taken into account in arriving at our own 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 10% per annum rate.

We also apply 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. This debt must be recorded at the estimated fair value as if Devon had issued it. However, significant judgment by Devon is usually not required in these situations due to the existence of comparable market values of debt issued by Devon's peer companies.

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 will require Devon to estimate the fair values of our assets and liabilities. Therefore, considerable judgment similar to that described above in connection with estimating the fair value of an acquired company in a business combination will be required to assess goodwill for impairment.

2002 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, 2001 reserve reports and other data in Devon's possession or available from third parties. We caution that 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 and production and sale of oil and gas. These risks include, but are not limited to, price volatility, inflation or lack of availability of goods and services, environmental risks, drilling risks, regulatory changes, the uncertainty inherent in estimating future oil and gas production or reserves, and other risks as outlined below. Additionally, future gas services revenues and expenses are subject to all of the risks and uncertainties normally incident to the gas services 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, 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 growth, weather and other substantially variable factors. These factors are beyond our control and are difficult to predict. In addition to volatility in general, Devon's oil, gas and NGL prices may vary considerably due to differences between regional markets, transportation availability and demand for different grades of oil, gas and NGLs. Substantially all of Devon's revenues are attributable to sales of these three commodities. Consequently, our 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 and gas 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 we operate. 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 natural gas and NGLs are based on the assumption that market demand and prices for 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 2002 will be substantially similar to those of 2001, unless otherwise noted. Given the general limitations expressed herein, Devon's forward-looking statements for 2002 are set forth below. Unless otherwise noted, all of the following dollar amounts are expressed in U.S. dollars. Those 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 2002 exchange rate may vary materially from this estimated rate. Such variations could have a material effect on the following Canadian estimates.

The following forward-looking data excludes the financial and operating effects of potential property acquisitions or divestitures, except for the Mitchell acquisition and except as discussed in "Property Acquisitions and Divestitures." The timing and ultimate results of such acquisition and divestiture activity is difficult to predict, and may vary materially from that discussed in this report.

Geographic Reporting Areas for 2002 The following estimates of production, average price differentials and capital expenditures are provided separately for each of the following geographic areas:

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

YEAR 2002 POTENTIAL OPERATING ITEMS

The estimates related to oil, gas and NGL production, operating costs and DD&A set forth in the following paragraphs are based on estimates for Devon's properties other than those that have been designated for possible sale (See "Property Acquisitions and Divestitures"). Therefore, the following estimates exclude the results of the potential sale properties for the entire year.

Oil, Gas and NGL Production Set forth in the following paragraphs are individual estimates of Devon's oil, gas and NGL production for 2002. On a combined basis, Devon estimates its 2002 oil, gas and NGL production will total between 175.4 and 186.4 MMBoe. Of this total, approximately 92% is estimated to be produced from reserves classified as proved at December 31, 2001.

Oil Production Devon expects its oil production to total between 34.5 and 36.7 MMBbls. Of this total, approximately 95% is estimated to be produced from reserves classified as proved at December 31, 2001. The expected ranges of production by area are as follows:

	(MMBbls)
United States	18.3 to 19.5
Canada	14.4 to 15.3
International	1.8 to 1.9

Oil Prices – Fixed Through certain forward oil sales agreements assumed in the 2000 Santa Fe Snyder merger, the price on a portion of Devon's 2002 oil production has been fixed. These agreements fixed the price on 2.5 MMBbls of 2002 oil production at an average price of $16.84 per Bbl. It should be noted that these forward sales apply only to production in the first eight months of 2002.

Devon has executed price swaps attributable to eight MMBbls of domestic production at an average price of $23.85 per Bbl. Additionally, Devon has entered into price swaps attributable to Canadian production of 1.6 MMBbls at an average price of $20.33 per Bbl.

Oil Prices – Floating For oil production for which prices have not been fixed, Devon's average prices are expected to differ from the NYMEX price as set forth in the following table.

	EXPECTED RANGE OF OIL PRICES LESS THAN NYMEX PRICE
United States	($2.35) to ($1.35)
Canada	($6.05) to ($4.05)
International	($4.05) to ($3.05)

Devon has also entered into costless price collars that set a floor price and a ceiling price for 7.3 MMBbls of United States oil production that otherwise is subject to floating prices. The collars have a floor and ceiling price per Bbl of $23.00 and $28.19, respectively. The floor and ceiling prices are based on the NYMEX price. The NYMEX price is the monthly average of settled prices on each trading day for West Texas Intermediate Crude oil delivered at Cushing, Oklahoma. 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.

Gas Production Devon expects its gas production to total between 747 Bcf and 793 Bcf. Of this total, approximately 90% is estimated to be produced from reserves classified as proved at December 31, 2001. The expected ranges of production are as follows:

	(Bcf)
United States	473 to 502
Canada	274 to 291

Gas Prices – Fixed Through various price swaps and fixed-price physical delivery contracts, Devon has fixed the price we will receive on a portion of our natural gas production. The following tables include information on this fixed-price production. 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.

	FIRST HALF OF 2002		SECOND HALF OF 2002	
	MCF/DAY	PRICE/MCF	MCF/DAY	PRICE/MCF
United States	264,671	$ 3.01	198,346	$ 3.19
Canada	192,983	$ 1.88	121,758	$ 1.69

Gas Prices – Floating For the natural gas production for which prices have not been fixed, Devon's average prices are expected to differ from the NYMEX price as set forth in the following table. The NYMEX price is determined to be the first-of-month South Louisiana Henry Hub price index as published monthly in *Inside FERC.*

	EXPECTED RANGE OF GAS PRICES GREATER THAN (LESS THAN) NYMEX PRICE
United States	($0.45) to $0.05
Canada	($0.75) to ($0.25)

Devon has also entered into costless price collars that set a floor and ceiling price for a portion of our 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 our realized prices for the production volumes related to the collars.

We have entered into costless collars concerning our 2002 gas production. To simplify presentation, these collars have been aggregated in the following table according to similar floor 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 Devon's estimates of 2002 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.*

	FIRST HALF OF 2002			SECOND HALF OF 2002		
AREA (RANGE OF FLOOR PRICES)	MMBtu/ DAY	FLOOR PRICE PER MMBtu	CEILING PRICE PER MMBtu	MMBtu/ DAY	FLOOR PRICE PER MMBtu	CEILING PRICE PER MMBtu
United States ($3.35 - $3.65)	285,000	$ 3.52	$ 7.37	285,000	$ 3.52	$ 7.37
United States ($2.96 - $3.11)	130,000	$ 3.01	$ 4.53	–	$ –	$ –
United States ($2.75 - $2.79)	35,000	$ 2.76	$ 3.72	35,000	$ 2.76	$ 3.72
Canada ($3.54 - $3.72)	23,705	$ 3.64	$ 6.82	23,705	$ 3.64	$ 6.82
Canada ($3.19 - $3.32)	9,481	$ 3.26	$ 4.50	–	$ –	$ –
Canada ($2.72 - $2.99)	34,481	$ 2.79	$ 3.88	25,000	$ 2.72	$ 3.67

NGL Production Devon expects its production of NGLs to total between 16.4 million barrels and 17.5 million barrels. Of this total, 98% is estimated to be produced from reserves classified as proved at December 31, 2001. The expected ranges of production are as follows:

	(MMBbls)
United States	11.9 to 12.7
Canada	4.5 to 4.8

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

These factors increase the uncertainty inherent in estimating future gas services revenues and expenses. Given these uncertainties, we estimate that 2002 gas services revenues will be between $917 million and $974 million and gas services expenses will be between $709 million and $752 million.

Other Revenues Devon's other revenues in 2002 are expected to be between $14 million and $18 million.

Production and Operating Expenses Devon's production and operating expenses include lease operating expenses, transportation costs and production taxes. These expenses vary in response to several factors. Among the most significant of these factors are additions to or deletions from Devon's property base, changes in production tax rates, changes in the general price level of services and materials that are used in the operation of the properties and the amount of repair and workover activity required. Oil, natural gas and NGL prices also have an effect on lease operating expense and impact the economic feasibility of planned workover projects.

Given these uncertainties, Devon estimates that lease operating expenses will be between $540 million and $574 million, transportation costs will be between $153 million and $163 million and production taxes will be between 3.9% and 4.4% of consolidated oil, natural gas and NGL revenues.

Depreciation, Depletion and Amortization ("DD&A") The 2002 oil and gas property DD&A rate will depend on various factors. Most notable among such factors are the amount of proved reserves that will be added from drilling or acquisition efforts compared to the costs incurred for such efforts, and the revisions to Devon's year-end 2001 reserve estimates that, based on prior experience, are likely to be made during 2002.

Oil and gas property related DD&A expense is expected to be between $1.1 billion and $1.3 billion. Additionally, Devon expects its DD&A expense related to non-oil and gas property fixed assets to total between $88 million and $93 million. This range includes $54 million to $57 million related to gas services assets. Based on these DD&A amounts and the production estimates set forth earlier, Devon expects its consolidated DD&A rate will be between $6.52 per Boe and $6.93 per Boe.

General and Administrative Expenses ("G&A") Devon's G&A includes the costs of many different goods and services used in support of its business. These goods and services are subject to general price level increases or decreases. In addition, Devon's G&A varies with its level of activity and the related staffing needs as well as with the amount of professional services required during any given period. Should our needs or the prices of the required goods and services differ significantly from current expectations, actual G&A could vary materially from the estimate. Given these limitations, consolidated G&A is expected to be between $174 million and $184 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 2002 from sales of oil, natural gas and NGLs and the resulting cash flow. The proceeds and the timing of the potential property sales in 2002 will also affect interest expense. Such proceeds could be used to retire either fixed-rate debt or variable-rate debt. At this time, the amount of proceeds and the timing of such property sales, as well as the application of the proceeds, are not possible to predict accurately. (See "Property Acquisitions and Divestitures.") These factors increase the margin of error inherent in estimating future interest expense. Other factors which 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 2002 other than the assumption of $211 million of such debt from Mitchell, Devon's average balance of fixed rate debt during 2002 will be $5.7 billion. The interest expense in 2002 related to this fixed-rate debt will be approximately $407 million. This fixed-rate debt removes the uncertainty of future interest rates from some, but not all, of Devon's long-term debt. Devon's floating rate debt is discussed in the following paragraphs.

After completion of the Mitchell acquisition, Devon had 100% of its $3.0 billion senior unsecured term loan credit facility borrowed. Interest on borrowings under this facility may be based, at Devon's option, on LIBOR plus a margin determined by Devon's long-term senior unsecured debt ratings. Regardless of the current debt ratings, the margin for borrowings based on LIBOR will be 100 basis points until June 17, 2002. As of January 31, 2002, the average interest rate on this facility was 2.8%.

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 45.0 to 47.5 basis points and the current Bankers Acceptance margin is 45.0 basis points. The total borrowed under these facilities was $50 million at December 31, 2001, at an average interest rate of 4.8%.

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. The total borrowed under the commercial paper program was $75 million at December 31, 2001, at an average interest rate of 3.5%. 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 $133 million Canadian dollars and $50 million U.S. dollars of its floating rate debt through interest-rate swap agreements at average rates of 6.4% and 5.9%, respectively. The Canadian dollar interest-rate swap agreements mature at various dates through July 2007 and the U.S. dollar swap agreement matures in May 2003.

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 lower of cost or fair value of unproved properties. 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 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. Because the ceiling calculation dictates that prices in effect as of the last day of the applicable quarter are held constant indefinitely, 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, they can be either substantially higher or lower than Devon's long-term price forecast that is a barometer for true fair value. Therefore, oil and gas property writedowns that result from applying the full cost ceiling limitation should not be viewed as absolute indicators of a reduction of the ultimate value of the related reserves. This is because they are caused by fluctuations in price as opposed to reductions to the underlying quantities of reserves.

Devon recorded writedowns to its domestic and Canadian oil and gas properties as of December 31, 2001. The year-end 2001 prices used to calculate the ceiling were a NYMEX oil price of $19.84 per barrel, and a Henry Hub gas price of $2.65 per MMBtu. If oil or gas prices at the end of future quarters drop below these year-end 2001 prices, or if Devon reduces its estimates of proved reserve quantities, further writedowns would likely occur. Also, in January 2002, Devon closed its merger with Mitchell. The oil and gas properties acquired in this transaction were recorded at their estimated fair value. The fair values were based on Devon's estimates of future oil and gas prices, and these estimated prices were higher than the year-end 2001 market prices for oil and gas. Therefore, the Mitchell properties were booked at amounts which would have exceeded the related full cost ceiling calculation as of the end of 2001. This increases the likelihood that Devon will incur further property writedowns of its domestic oil and gas properties.

Effects of Changes in Foreign Currency Rates In the October 2001 Anderson acquisition, Devon's subsidiary, Devon Canada, assumed $400 million of long-term debt which is denominated in U.S. dollars. This debt matures in 2011. Changes in the exchange rate between the U.S. dollar and the Canadian dollar from October 15, when Devon acquired Anderson, to the dates of repayment will increase or decrease the expected amount of Canadian dollars eventually required to repay the 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 2002. However, for every $0.01 change in the exchange rate, Devon will record either revenue 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.

With the devaluation of the Argentine peso in January 2002, changes in the exchange rate between the U.S. dollar and the Argentine peso will also result in gains or losses for the period in which the exchange rate changes. The functional currency of Devon's Argentine subsidiary is the U.S. dollar. As a result, changes in the exchange rate between the U.S. dollar and the Argentine peso will increase or decrease the expected amount of Argentine pesos eventually collected or paid for transactions that are settled in pesos. Because of the variability of the exchange rate, it is not possible to estimate the deferred effect which will be recorded in 2002. The resulting revenue or expense in U.S. dollars will depend on the currency exchange rate in effect throughout the year.

Income Taxes Devon's financial income tax rate in 2002 will vary materially depending on the actual amount of financial pre-tax earnings. There are certain tax deductions and credits that will have a fixed impact on 2002's income tax expense regardless of the level of pre-tax earnings that are produced. Due to the significance of these deductions and credits as compared to potential pre-tax earnings, it is not possible to estimate an accurate single range of financial income tax rates that would apply to all the possible levels of pre-tax earnings during 2002. Therefore, the following estimates are provided based on various ranges of financial pre-tax earnings for 2002.

	INCOME TAX EXPENSE (BENEFIT) RATE		
PRE-TAX EARNINGS	CURRENT	DEFERRED	TOTAL
$100 - $225 million	65% to 40%	(130%) to (50%)	(65%) to (10%)
$226 - $450 million	40% to 35%	(50%) to (20%)	(10%) to 15%
$451 - $675 million	35% to 30%	(20%) to (10%)	15% to 20%

It is uncertain whether Devon's pre-tax earnings will be within the ranges presented in the above table. Among the factors which could cause Devon's pre-tax earnings to fall outside these ranges is price volatility. In addition to price volatility's effect on revenues, such volatility could also cause Devon to incur a full cost reduction of oil and gas properties. Variances in revenues or expenses resulting from price volatility could cause Devon's pre-tax earnings to fall outside the ranges presented.

Property Acquisitions and Divestitures Although we have completed several major property acquisitions in recent years, these transactions are opportunity driven. Thus, Devon does not "budget," nor can we reasonably predict, the timing or size of such possible acquisitions, if any, other than the Mitchell acquisition, which closed on January 24, 2002.

During 2002, Devon contemplates the disposition of certain oil and gas properties (the "Disposition Properties"). The Disposition Properties are predominantly properties that are either outside of Devon's core-operating areas or otherwise do not fit Devon's current strategic objectives. The Disposition Properties are located in the U.S., Canada and international areas. At this time, Devon is in the early stages of the disposition process, and it is impossible to identify when, or if, the dispositions will occur.

The estimates of Devon's 2002 results previously set forth exclude any results from the Disposition Properties. The Disposition Properties' actual contributions to Devon's 2002 operating results will depend upon the timing of the dispositions. The estimated full-year 2002 results from the Disposition Properties (which are not included in the previous 2002 estimates included in this report) are as follows:

	EXPECTED RANGE OF PRODUCTION			
	OIL (MMBbls)	GAS (Bcf)	NGL (MMBbls)	TOTAL (MMBoe)
United States	6.8 to 7.2	45 to 48	0.6 to 0.7	14.9 to 15.9
Canada	2.9 to 3.1	13 to 14	0.3 to 0.4	5.4 to 5.8
International	7.1 to 7.5	10 to 11	0.1 to 0.2	8.9 to 9.5
Total	16.8 to 17.8	68 to 73	1.0 to 1.3	29.2 to 31.2

	EXPECTED RANGE OF EXPENSE (IN MILLIONS)
Lease operating expenses	$178 to $189
Transportation costs	$ 10 to $ 11
DD&A	$195 to $207

YEAR 2002 POTENTIAL CAPITAL EXPENDITURES AND OTHER CASH USES

Capital Expenditures Although we have completed several major property acquisitions in recent years, these transactions are opportunity driven. Thus, Devon does not "budget," nor can we reasonably predict, the timing or size of such possible acquisitions, if any, other than the Mitchell acquisition.

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 differ materially from Devon's expectations for its future production, some projects may be accelerated or deferred and, consequently, may increase or decrease total 2002 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, the company expects its 2002 capital expenditures for drilling and development efforts, plus related facilities, to total between $1.2 billion and $1.4 billion. These amounts include between $495 million and $595 million for drilling and facilities costs related to reserves classified as proved as of year-end 2001. In addition, these amounts include between $365 million and $435 million for other low risk/reward projects and between $300 million and $350 million for new, higher risk/reward projects. Low risk/reward projects include development drilling that does not offset currently productive units and for which there is not a certainty of continued production from a known productive formation. Higher risk/reward projects include exploratory drilling to find and produce oil or gas in previously untested fault blocks or new reservoirs.

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

	DRILLING AND PRODUCTION FACILITIES EXPENDITURES			
	UNITED STATES	CANADA	INTERNATIONAL	TOTAL
		(IN MILLIONS)		
Related to Proved Reserves	$ 435 - $ 495	$ 15 - $ 35	$ 45 - $ 65	$ 495 - $ 595
Lower Risk/Reward Projects	$ 170 - $ 200	$ 195 - $ 225	$ 0 - $ 10	$ 365 - $ 435
Higher Risk/Reward Projects	$ 70 - $ 80	$ 210 - $ 240	$ 20 - $ 30	$ 300 - $ 350
Total	$ 675 - $ 775	$ 420 - $ 500	$ 65 - $ 105	$ 1,160 - $ 1,380

In addition to the above expenditures for drilling and development, Devon expects to spend between $135 million and $165 million on our gas services assets, which include gas processing plants and gas transport pipelines. Devon also expects to capitalize between $85 million and $105 million of G&A expenses in accordance with the full cost method of accounting. Devon also expects to pay between $20 million and $30 million for plugging and abandonment charges, and to spend between $15 million and $25 million for non-oil and gas property fixed assets.

The above capital expenditure estimates do not include the cost to acquire Mitchell in 2002. At closing, Devon paid approximately $1.6 billion to the Mitchell stockholders. We also issued approximately 30 million shares of Devon common stock at closing. For accounting purposes, the Devon shares were valued at $50.95 per share, which was the value at the time the Mitchell acquisition was announced in August 2001. This resulted in the shares of Devon common stock issued at closing to be valued at approximately $1.5 billion.

The actual allocation of the Mitchell acquisition cost to the various assets and liabilities will not be final until sometime later in 2002. However, the preliminary allocation of the acquisition cost to fixed assets was as follows:

Proved oil and gas properties	$1.5 billion
Unproved oil and gas properties	$0.7 billion
Gas services facilities and equipment	$0.8 billion
	$3.0 billion

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 155 million shares of common stock outstanding after completion of the Mitchell acquisition, 2002 dividends are expected to approximate $31 million. Also, Devon has $150 million of 6.49% cumulative preferred stock upon which we will pay $10 million of dividends in 2002.

IMPACT OF RECENTLY ISSUED ACCOUNTING STANDARDS NOT YET ADOPTED Effective January 1, 2002, Devon 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. Also, Devon adopted the provisions of SFAS No. 141, *Business Combinations*, at the time of issuance in July 2001 for business combinations after that date. Under the provisions of SFAS No. 141 and the applicable portions of SFAS No. 142, any goodwill and any intangible asset determined to have an indefinite useful life that are acquired in a purchase business combination completed after June 30, 2001 are not amortized, but are to be evaluated for impairment in accordance with the appropriate pre- SFAS No. 142 accounting literature. Goodwill and intangible assets acquired in business combinations completed before July 1, 2001 continued to be amortized prior to the full adoption of SFAS No. 142.

We will perform an assessment of whether there is an indication that goodwill is impaired as of January 1, 2002. We will identify our reporting units and determine the carrying value of each reporting unit by assigning the assets and liabilities, including the existing goodwill, to those reporting units as of January 1, 2002. Devon then has until June 30, 2002, to determine the fair value of each reporting unit and compare it to the reporting unit's carrying amount. To the extent a reporting unit's carrying amount exceeds its fair value, an indication exists that the reporting unit's goodwill may be impaired and Devon must perform the second step of the transitional impairment test. In the second step, Devon must compare the implied fair value of the reporting unit's goodwill, determined by allocating the reporting unit's fair value to all of it assets (recognized and unrecognized) and liabilities in a manner similar to a purchase price allocation in accordance with SFAS No. 141, to its carrying amount, both of which would be measured as of January 1, 2002. This second step is required to be completed as soon as possible, but no later than the end of 2002. Any transitional impairment loss will be recognized as the cumulative effect of a change in accounting principle in Devon's 2002 statement of operations.

As of January 1, 2002, Devon had unamortized goodwill in the amount of $2.2 billion, which was subject to the transition provisions of SFAS Nos. 141 and 142. Devon has not completed its assessment of the impact of adopting the remaining provisions of SFAS Nos. 141 and 142 on Devon's financial statements. However, we do not believe that a transitional impairment loss will be required to be recognized.

Also 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 fair value. 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." We expect to use a valuation technique such as expected present value to estimate fair value.

The asset retirement cost equal to the 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 be required to 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 currently records estimated costs of dismantlement, removal, site reclamation, and other similar activities as part of depreciation, depletion, and amortization and does not record a separate liability for such amounts. Devon has not completed the assessment of the impact that adoption of SFAS No. 143 will have on its consolidated financial statements. However, we expect the amounts for capitalized oil and gas property costs and asset retirement obligations will increase.

In August 2001, the FASB issued SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, which 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). SFAS No. 144 retains the fundamental provisions in SFAS No. 121 for recognizing and measuring impairment losses on long-lived assets held for use and long-lived assets to be disposed of by sale, while also resolving significant implementation issues associated with SFAS No. 121. For example, SFAS No. 144 provides guidance on how a long-lived asset that is used as part of a group should be evaluated for impairment, establishes criteria for when a long-lived asset is held for sale, and prescribes the accounting for a long-lived asset that will be disposed of other than by sale. SFAS No. 144 retains the basic provisions of APB No. 30 on how to present discontinued operations in the income statement but broadens that presentation to include a component of an entity (rather than a segment of a business). Unlike SFAS No. 121, an impairment assessment under SFAS No. 144 will never result in a write-down of goodwill. Rather, goodwill is evaluated for impairment under SFAS No. 142, *Goodwill and Other Intangible Assets*.

Devon adopted SFAS No. 144 effective January 1, 2002. We do not expect the adoption of SFAS No. 144 for long-lived assets held for use or for disposal to have a material impact on Devon's financial statements. This is because Devon utilizes the full-cost method of accounting for oil and gas exploration and development activities and the impairment assessment under SFAS No. 144 is largely unchanged from SFAS No. 121.

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 and gas prices, interest rates and foreign currency exchange rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. This forward-looking information provides indicators of how we view and manage our ongoing market risk exposures. All of Devon's market risk sensitive instruments were entered into for purposes other than trading.

COMMODITY PRICE RISK Devon's major market risk exposure is in the pricing applicable to its oil and gas 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 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 and natural gas prices at targeted levels and to manage our exposure to oil and gas price fluctuations. We do not hold or issue derivative instruments for trading purposes.

Devon's total hedged positions as of January 31, 2002 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 our oil and natural gas production in 2002, 2003 and 2004. The following tables include information on this production. Where necessary, the prices have been adjusted for certain transportation costs that are netted against the price recorded by Devon, and the price has also been adjusted for the Btu content of the gas production that has been hedged.

	OIL PRODUCTION			
	FIRST HALF OF 2002		**SECOND HALF OF 2002**	
	Bbls/**DAY**	**PRICE**/Bbl	Bbls/**DAY**	**PRICE**/Bbl
United States	22,000	$ 23.85	22,000	$ 23.85
Canada	4,350	$ 20.33	4,350	$ 20.33

	GAS PRODUCTION			
	FIRST HALF OF 2002		**SECOND HALF OF 2002**	
	Mcf/**DAY**	**PRICE**/Mcf	Mcf/**DAY**	**PRICE**/Mcf
United States	211,936	$ 3.11	198,346	$ 3.19
Canada	40,673	$ 2.13	33,472	$ 2.12
	FIRST HALF OF 2003		**SECOND HALF OF 2003**	
	Mcf/**DAY**	**PRICE**/Mcf	Mcf/**DAY**	**PRICE**/Mcf
United States	89,726	$ 3.50	100,000	$ 3.32
Canada	5,000	$ 2.49	5,000	$ 2.03
	FIRST HALF OF 2004		**SECOND HALF OF 2004**	
	Mcf/**DAY**	**PRICE**/Mcf	Mcf/**DAY**	**PRICE**/Mcf
United States	–	$ –	–	$ –
Canada	5,000	$ 2.58	3,342	$ 2.03

Costless Price Collars Devon has also entered into costless price collars that set a floor and ceiling price for a portion of our 2002 and 2003 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 our 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 table are weighted averages of all the various collars.

	OIL PRODUCTION					
	FIRST HALF OF 2002			**SECOND HALF OF 2002**		
	Bbls/**DAY**	**FLOOR PRICE PER** Bbl	**CEILING PRICE PER** Bbl	Bbls/**DAY**	**FLOOR PRICE PER** Bbl	**CEILING PRICE PER** Bbl
United States	20,000	$ 23.00	$ 28.19	20,000	$ 23.00	$ 28.19

	GAS PRODUCTION					
	FIRST HALF OF 2002			**SECOND HALF OF 2002**		
	MMBtu/**DAY**	**FLOOR PRICE PER** MMBtu	**CEILING PRICE PER** MMBtu	MMBtu/**DAY**	**FLOOR PRICE PER** MMBtu	**CEILING PRICE PER** MMBtu
United States	450,000	$ 3.32	$ 6.27	320,000	$ 3.44	$ 6.97
Canada	67,667	$ 3.15	$ 5.00	48,705	$ 3.17	$ 5.20
	FIRST HALF OF 2003			**SECOND HALF OF 2003**		
	MMBtu/**DAY**	**FLOOR PRICE PER** MMBtu	**CEILING PRICE PER** MMBtu	MMBtu/**DAY**	**FLOOR PRICE PER** MMBtu	**CEILING PRICE PER** MMBtu
United States	265,000	$ 3.18	$ 4.22	265,000	$ 3.18	$ 4.22
Canada	80,000	$ 3.27	$ 4.07	80,000	$ 3.27	$ 4.07

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 our commodity hedging instruments. At January 31, 2002, a 10% increase in the underlying commodities' prices would have reduced the fair value of our commodity hedging instruments by $118 million.

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

The price Devon will receive on a portion of its 2002 oil production has been fixed through certain forward oil sales assumed in the 2000 Santa Fe Snyder merger. From January 2002 through August 2002, 311,000 barrels of oil production per month have been fixed at an average price of $16.84 per barrel.

For each of the years 2002 through 2011, Devon has fixed-price gas contracts that cover approximately 24 Bcf, 19 Bcf, 19 Bcf, 19 Bcf, 19 Bcf, 17 Bcf, 16 Bcf, 16 Bcf, 15 Bcf and 13 Bcf, respectively, of Canadian production. Devon also has Canadian gas volumes subject to fixed-price contracts in the years from 2012 through 2016, but the yearly volumes are less than 1 Bcf.

INTEREST RATE RISK At December 31, 2001, Devon had long-term debt outstanding of $6.6 billion. Of this amount, $5.4 billion, or 82%, bears interest at fixed rates averaging 7.0%. The remaining $1.2 billion of debt outstanding bears interest at floating rates which averaged 3.0%. In January 2002, Devon borrowed the remaining $2 billion on its $3 billion term loan credit facility to fund the Mitchell acquisition. The interest rate on the term loan credit facility is floating.

The terms of Devon’s various floating rate debt facilities (revolving credit facilities, commercial paper and term loan credit facility) allow interest rates to be fixed at Devon's option for periods of between seven to 180 days. A 10% increase in short-term interest rates on the floating-rate debt outstanding as of December 31, 2001, as adjusted for the new floating rate debt drawn down in January 2002, would equal approximately 30 basis points. Such an increase in interest rates would increase Devon's 2002 interest expense by approximately $4 million. This assumes borrowed amounts remain outstanding for the remainder of 2002.

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 6.2% on $132 million of debt in 2002, 6.3% on $97 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 our interest rate swap instruments. At January 31, 2002, a 10% increase in the underlying interest rates would have decreased the fair value of Devon's interest rate swaps by $1 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, Devon’s 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. 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. These swaps require Devon to sell $30 million in 2002 and $12 million in 2003 at average Canadian-to-U.S. exchange rates of $0.680 and $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, 2001 exchange rate, these swaps would result in a decrease to gas sales during 2002 and 2003 of approximately $2 million and $1 million, respectively. A further $0.03 decrease in the Canadian-to-U.S. dollar exchange rate would result in an additional decrease to 2002 and 2003 gas sales of approximately $1 million in each year.

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 nine 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 2001 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

J. Michael Lacey
Senior Vice President

Marian J. Moon
Senior Vice President

Darryl G. Smette
Senior Vice President

Brian J. Jennings
Senior Vice President

Duke R. Ligon
Senior Vice President

John Richels
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, 2001, 2000 and 1999, 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 did not audit the 1999 financial statements of Santa Fe Snyder Corporation, a wholly-owned subsidiary, which statements reflect total assets constituting 24% in 1999 of the related consolidated totals, and which statements reflect total revenues constituting 41% in 1999 of the related consolidated totals. The 1999 financial statements of Santa Fe Snyder Corporation were audited by other auditors whose report has been furnished to us, and our opinion, insofar as it relates to the amounts included for Santa Fe Snyder Corporation in 1999 is based solely on the report of the other auditors.

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 and the report of the other auditors provide a reasonable basis for our opinion.

In our opinion, based on our audits and the report of the other auditors, 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, 2001, 2000 and 1999, 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*.

KPMG LLP

Oklahoma City, Oklahoma
February 5, 2002

DEVON ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

DECEMBER 31, (IN MILLIONS, EXCEPT SHARE DATA)	2001	2000	1999
ASSETS			
Current assets:			
Cash and cash equivalents	$ 193	228	173
Accounts receivable	537	598	316
Inventories	41	47	39
Deferred income taxes	–	9	5
Fair value of financial instruments	195	–	–
Income taxes receivable	68	–	–
Investments and other current assets	47	52	57
Total current assets	1,081	934	590
Property and equipment, at cost, based on the full cost method of accounting for oil and gas properties ($1,939, $315 and $301 excluded from amortization in 2001, 2000 and 1999, respectively)	15,598	9,709	8,592
Less accumulated depreciation, depletion and amortization	6,570	4,799	4,168
	9,028	4,910	4,424
Investment in ChevronTexaco Corporation common stock, at fair value	636	599	614
Fair value of financial instruments	31	–	–
Goodwill	2,206	289	323
Other assets	202	128	145
Total assets	$ 13,184	6,860	6,096
LIABILITIES AND STOCKHOLDERS' EQUITY			
Current liabilities:			
Accounts payable:			
Trade	465	321	267
Revenues and royalties due to others	170	116	67
Income taxes payable	30	66	13
Accrued interest payable	102	23	28
Merger related expenses payable	7	52	36
Fair value of financial instruments	15	–	–
Deferred income taxes	57	–	–
Accrued expenses	73	51	56
Total current liabilities	919	629	467
Other liabilities	179	164	263
Debentures exchangeable into shares of ChevronTexaco Corporation common stock	649	760	760
Other long-term debt	5,940	1,289	1,656
Deferred revenue	51	114	105
Fair value of financial instruments	45	–	–
Deferred income taxes	2,142	627	324
Stockholders' equity:			
Preferred stock of $1.00 par value ($100 liquidation value) Authorized 4,500,000 shares; issued 1,500,000 in 2001, 2000 and 1999	1	1	1
Common stock of $.10 par value Authorized 400,000,000 shares; issued 126,132,000 in 2001, 128,638,000 in 2000 and 126,323,000 in 1999	13	13	13
Additional paid-in capital	3,610	3,564	3,492
Accumulated deficit	(147)	(215)	(909)
Accumulated other comprehensive loss	(28)	(85)	(65)
Unamortized restricted stock awards	–	(1)	–
Treasury stock, at cost: 3,754,000 shares in 2001 and 330,000 shares in 1999	(190)	–	(11)
Total stockholders' equity	3,259	3,277	2,521
Commitments and contingencies (Notes 12 and 13)			
Total liabilities and stockholders' equity	$ 13,184	6,860	6,096

See accompanying notes to consolidated financial statements

DEVON ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

YEAR ENDED D **ECEMBER 31,** (IN MILLIONS, EXCEPT PER SHARE AMOUNTS)		2001	2000	1999
REVENUES				
Oil sales	$	958	1,079	561
Gas sales		1,890	1,485	628
Natural gas liquids sales		132	154	68
Other		95	66	21
Total revenues		3,075	2,784	1,278
COSTS AND EXPENSES				
Lease operating expenses		531	441	299
Transportation costs		83	53	34
Production taxes		117	103	45
Depreciation, depletion and amortization of property and equipment		876	693	406
Amortization of goodwill		34	41	16
General and administrative expenses		111	93	81
Expenses related to mergers		1	60	17
Interest expense		220	155	109
Effects of changes in foreign currency exchange rates		13	3	(13)
Distributions on preferred securities of subsidiary trust		–	–	7
Change in fair value of financial instruments		2	–	–
Reduction of carrying value of oil and gas properties		1,003	–	476
Total costs and expenses		2,991	1,642	1,477
Earnings (loss) before income taxes, extraordinary item and cumulative effect of change in accounting principle		84	1,142	(199)
INCOME TAX EXPENSE (BENEFIT)				
Current		71	131	23
Deferred		(41)	281	(72)
Total income tax expense (benefit)		30	412	(49)
Earnings (loss) before extraordinary item and cumulative effect of change in accounting principle		54	730	(150)
Extraordinary loss		–	–	(4)
Earnings (loss) before cumulative effect of change in accounting principle		54	730	(154)
Cumulative effect of change in accounting principle		49	–	–
Net earnings (loss)		103	730	(154)
Preferred stock dividends		10	10	4
Net earnings (loss) applicable to common shareholders	$	93	720	(158)
Net earnings (loss) per average common share outstanding:				
Before extraordinary loss and cumulative effect of change in accounting principle:				
Basic	$	0.34	5.66	(1.64)
Diluted	$	0.34	5.50	(1.64)
Before cumulative effect of change in accounting principle:				
Basic	$	0.34	5.66	(1.68)
Diluted	$	0.34	5.50	(1.68)
Applicable to common shareholders:				
Basic	$	0.73	5.66	(1.68)
Diluted	$	0.72	5.50	(1.68)
Weighted average common shares outstanding:				
Basic		128	127	94
Diluted		130	132	99

See accompanying notes to consolidated financial statements

DEVON ENERGY CORPORATION AND SUBSIDIARIES

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, 1998	$	–	7	1,524	(737)	(36)	(1)	(7)	750
Comprehensive loss:									
Net loss		–	–	–	(154)	–	–	–	(154)
Other comprehensive earnings (loss), net of tax:									
Foreign currency translation adjustments		–	–	–	–	7	–	–	7
Unrealized loss on marketable securities		–	–	–	–	(36)	–	–	(36)
Other comprehensive loss		–	–	–	–	–	–	–	(29)
Comprehensive loss									(183)
Stock issued		1	6	1,967	(1)	–	–	8	1,981
Stock repurchased		–	–	–	–	–	–	(12)	(12)
Tax benefit related to employee stock options		–	–	1	–	–	–	–	1
Dividends on common stock		–	–	–	(13)	–	–	–	(13)
Dividends on preferred stock		–	–	–	(4)	–	–	–	(4)
Amortization of restricted stock awards		–	–	–	–	–	1	–	1
BALANCE AS OF DECEMBER 31, 1999		1	13	3,492	(909)	(65)	–	(11)	2,521
Comprehensive loss:									
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) losses 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

See accompanying notes to consolidated financial statements

DEVON ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

YEAR ENDED DECEMBER 31, (IN MILLIONS)	2001	2000	1999
CASH FLOWS FROM OPERATING ACTIVITIES			
Net earnings (loss)	$ 103	730	(154)
Adjustments to reconcile net earnings (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization of property and equipment	876	693	406
Amortization of goodwill	34	41	16
Accretion (amortization) of discounts (premiums) on long-term debt, net	26	3	(1)
Effects of changes in foreign currency exchange rates	13	3	(13)
Change in fair value of financial instruments	2	–	–
Reduction of carrying value of oil and gas properties	1,003	–	476
Loss (gain) on sale of assets	2	(1)	5
Deferred income tax expense (benefit)	(41)	281	(72)
Cumulative effect of change in accounting principle	(49)	–	–
Other	(3)	4	2
Changes in assets and liabilities, net of effects of acquisitions of businesses:			
Decrease (increase) in:			
Accounts receivable	191	(284)	(93)
Inventories	15	(8)	(9)
Income tax receivable	(68)	–	–
Investments and other current assets	2	10	(41)
(Decrease) increase in:			
Accounts payable	29	99	(23)
Income taxes payable	(117)	61	(19)
Accrued interest and expenses	(46)	3	(38)
Deferred revenue	(63)	8	91
Long-term other liabilities	(23)	(24)	(1)
Net cash provided by operating activities	1,886	1,619	532
CASH FLOWS FROM INVESTING ACTIVITIES			
Proceeds from sale of property and equipment	41	101	114
Proceeds from sale of investments	–	13	–
Capital expenditures, including acquisitions of businesses	(5,326)	(1,280)	(883)
(Increase) decrease in other assets	–	(7)	1
Net cash used in investing activities	(5,285)	(1,173)	(768)
CASH FLOWS FROM FINANCING ACTIVITIES			
Proceeds from borrowings of long-term debt, net of issuance costs	6,199	2,580	1,945
Principal payments on long-term debt	(2,638)	(2,952)	(2,089)
Issuance of common stock, net of issuance costs	48	51	530
Repurchase of common stock	(204)	(10)	(12)
Issuance of treasury stock	–	25	6
Dividends paid on common stock	(25)	(22)	(13)
Dividends paid on preferred stock	(10)	(10)	(4)
(Decrease) increase in long-term other liabilities	–	(52)	14
Net cash provided by (used in) financing activities	3,370	(390)	377
Effect of exchange rate changes on cash	(6)	(1)	1
Net (decrease) increase in cash and cash equivalents	(35)	55	142
Cash and cash equivalents at beginning of year	228	173	31
Cash and cash equivalents at end of year	$ 193	228	173

See accompanying notes to consolidated financial statements

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

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

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 managed in three divisions:

• the Gulf Division, which includes properties located primarily in the onshore south Texas and south Louisiana areas and offshore in the Gulf of Mexico;

• the Rocky Mountain Division, which includes properties located in the Rocky Mountains area of the United States stretching from the Canadian Border into northern New Mexico; and

• the Permian / Mid-Continent Division, which includes all domestic properties other than those included in the Gulf Division and the Rocky Mountain Division.

Devon's Canadian activities are located primarily in the Western Canadian Sedimentary Basin. Devon's international activities, outside of North America, are located primarily in Argentina, Azerbaijan, Indonesia and Gabon. 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 that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual amounts could differ from those estimates.

Property and Equipment

Devon follows the full cost method of accounting for its oil and gas properties. Accordingly, all costs incidental to the acquisition, exploration and development of oil and gas properties, including costs of undeveloped leasehold, dry holes and leasehold equipment, are capitalized. Internal costs incurred that are directly identified with acquisition, exploration and development activities undertaken by Devon for its own account, and which are not related to production, general corporate overhead or similar activities are also capitalized. For the years 2001, 2000 and 1999, such internal costs capitalized totaled $77 million, $62 million and $29 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 lower of cost or fair value of unproved properties. 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 3 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 ChevronTexaco Corporation common stock, which is classified as "available-for-sale," is reported at fair value, with the tax effected unrealized gain or loss 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."

Goodwill

Goodwill, which represents the excess of purchase price over the fair value of net assets acquired, acquired before June 30, 2001, is amortized by an equivalent unit-of-production method. Goodwill acquired after June 30, 2001, is not amortized. Devon assesses the recoverability of goodwill by determining whether the amortization of the goodwill balance over its remaining life can be recovered through undiscounted future operating cash flows of the acquired properties. The amount of goodwill impairment, if any, is measured based on projected discounted future operating cash flows using a discount rate reflecting Devon's average cost of funds. The assessment of the recoverability of goodwill will be impacted if estimated future operating cash flows are not achieved.

Accumulated goodwill amortization was $91 million, $57 million and $16 million at December 31, 2001, 2000 and 1999, respectively.

Effective January 1, 2002, Devon 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. Also, Devon adopted the provisions of SFAS No. 141, *Business Combinations*, and certain provisions of SFAS No. 142 in July 2001. Under the provisions of SFAS No. 142, any goodwill and any intangible asset determined to have an indefinite useful life that were acquired in a purchase business combination completed after June 30, 2001 are not amortized, but are to be evaluated for impairment at December 31, 2001, in accordance with the appropriate pre-SFAS No. 142 accounting. Goodwill and intangible assets acquired in business combinations completed before July 1, 2001 continued to be amortized prior to the adoption of the remaining provisions of SFAS No. 142.

Devon will perform an assessment of whether there is an indication that goodwill is impaired as of January 1, 2002. Devon will identify its reporting units and determine the carrying value of each reporting unit by assigning the assets and liabilities, including the existing goodwill, to those reporting units as of January 1, 2002. Devon has until June 30, 2002, to determine the fair value of each reporting unit and compare such value to the reporting unit's carrying amount. To the extent a reporting unit's carrying amount exceeds its fair value, an indication exists that the reporting unit's goodwill may be impaired and Devon must perform the second step of the transitional impairment test. In the second step, Devon must compare the implied fair value of the reporting unit's goodwill, determined by allocating the reporting unit's fair value to all of it assets (recognized and unrecognized) and liabilities in a manner similar to a purchase price allocation in accordance with SFAS No. 141, to its carrying amount, both of which would be measured as of January 1, 2002. This second step is required to be completed as soon as possible, but no later than the end of 2002. Any transitional impairment loss will be recognized as the cumulative effect of a change in accounting principle in Devon's 2002 statement of operations.

As of January 1, 2002, Devon had unamortized goodwill in the amount of $2.2 billion, which was subject to the transition provisions of SFAS Nos. 141 and 142. Devon has not completed its assessment of the impact on its financial statements of adopting SFAS Nos. 141 and 142. However, Devon does not believe that a transitional impairment loss will be required to be recognized.

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, cash settlements are made among the joint interest owners under a variety of arrangements.

Devon follows the sales method of accounting for gas 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.

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 Canadian oil and gas revenues that are predominantly based on U.S. dollar prices. 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. The oil and gas reference prices upon which the price hedging instruments are based reflect various market indices that have a high degree of historical correlation with actual prices received by Devon.

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 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 ($0.38 per basic share and $0.37 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 Corporation 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 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.

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.

Devon does not hold or issue derivative instruments for trading purposes. The majority of Devon's commodity price swaps and costless price collars, interest rate swaps, and foreign exchange rate swaps in place at January 1, 2001 through December 31, 2001 have been designated as cash flow hedges. Changes in the fair value of these derivatives are reported on the balance sheet in "Accumulated other comprehensive loss" ("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 and, as such, the realized gain of $30 million from settling these contracts is included in the 2001 consolidated statement of operations as other revenues.

During the third quarter of 2001, Devon also 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 7. 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 assesses the effectiveness of its hedges based on changes in the derivative's intrinsic value. The change in the time value of the derivative is excluded from the assessment of hedge effectiveness and, along with any ineffectiveness, is recorded on the statement of operations in "Change in fair value of derivative instruments." For the year ended December 31, 2001, Devon recorded a net charge of approximately $10 million which represented (i) the ineffectiveness of the various cash flow hedges and (ii) the component of the derivative instrument gain or loss excluded from the assessment of hedge effectiveness.

As of December 31, 2001, $180 million of net deferred gains 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' gains to earnings are primarily the production and sale of oil and gas which 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 34 months.

Devon recorded in its statements of operations a loss of $2 million for the year ended December 31, 2001 for the change in fair value of derivative instruments that do not qualify for hedge accounting treatment.

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 which are included in Note 10.

Major Purchasers

In 2001 and 2000, Enron Capital and Trade Resource Corporation accounted for 16% and 20%, respectively, of Devon's combined oil, gas and natural gas liquids sales. No purchaser accounted for over 10% of such revenues in 1999.

On December 2, 2001, Enron Corporation 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 or gas to Enron related entities. Devon incurred $3 million of losses 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, whereby deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of assets and liabilities and their respective tax bases, as well as the future tax consequences attributable to the future utilization of existing tax net operating loss and other types of carryforwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences and carryforwards are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date. U.S. deferred income taxes have not been provided on Canadian earnings 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.

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 2001 and 2000. The diluted loss per share calculations for 1999 produce results that are anti-dilutive. (The diluted calculation for 1999 reduced the net loss by $4.3 million and increased the common shares outstanding by 5.7 million shares.) Therefore, the diluted loss per share amounts for 1999 reported in the accompanying consolidated statements of operations are the same as the basic loss per share amounts.

	NET EARNINGS APPLICABLE TO COMMON STOCKHOLDERS	WEIGHTED AVERAGE COMMON SHARES OUTSTANDING	NET EARNINGS PER SHARE
	(IN MILLIONS)		
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 were not included in the 2001 dilution calculation because the inclusion was anti-dilutive.

Options to purchase approximately three million shares of Devon's common stock with exercise prices ranging from $48.13 per share to $89.66 per share (with a weighted average price of $56.11 per share) were outstanding at December 31, 2001, but were not included in the computation of diluted earnings per share for 2001 because the options' exercise price exceeded the average market price of Devon's common stock during the year. The excluded options for 2001 expire between February 18, 2002 and December 4, 2011. Options to purchase approximately one million shares of Devon's common stock with exercise prices ranging from $55.54 per share to $89.66 per share (with a weighted average price of $66.64 per share) were outstanding at December 31, 2000, but were not included in the computation of diluted earnings per share for 2000 because the options' exercise price exceeded the average market price of Devon's common stock during the year. All options were excluded from the diluted earnings per share calculations for 1999.

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, 2001, 2000 and 1999, 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, 1998	$ (35)	$ —	$ (1)	$ —	$ (36)
1999 activity	7	—	—	(60)	(53)
Deferred taxes	—	—	—	24	24
1999 activity, net of deferred taxes	7	—	—	(36)	(29)
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)**

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 2001, 2000 and 1999 at a per share rate of $0.05 per quarter. As adjusted for the pooling-of-interests method of accounting followed for the Santa Fe Snyder merger, annual dividends per share for 2001, 2000 and 1999 were $0.20, $0.17 and $0.14, 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 13 for a discussion of amounts recorded for these liabilities.

Reclassification

Certain of the 2000 and 1999 amounts in the accompanying consolidated financial statements have been reclassified to conform to the 2001 presentation.

2. BUSINESS COMBINATIONS AND PRO FORMA INFORMATION

Mitchell Acquisition

On January 24, 2002, Devon completed its acquisition of Mitchell Energy & Development Corp. ("Mitchell") for cash and stock. For each Mitchell common share outstanding, Mitchell stockholders received $31 cash and 0.585 of a share of Devon common stock. The purchase price was approximately $3.2 billion. The $1.6 billion cash portion of the purchase price was funded from the $3.0 billion senior unsecured term loan credit facility (see Note 7).

Because the Mitchell merger was not closed until 2002, it had no effect on Devon's 2001 financial condition or results of operations. See Note 19 for unaudited pro forma information concerning the Mitchell acquisition and the October 2001 acquisition of Anderson Exploration Ltd. ("Anderson").

Anderson 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 billion senior unsecured term loan credit facility (see Note 7).

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 preliminary allocation to assets and liabilities as of October 15, 2001, are shown below. The purchase price allocation is preliminary because certain items such as the tax basis of the assets and liabilities acquired and the allocation of fair value to undeveloped properties have not been completed.

		(IN MILLIONS, EXCEPT SHARE PRICE)
Calculation and preliminary 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		249
Long-term debt		1,017
Other long-term liabilities		7
Fair value of financial instruments		30
Deferred income taxes		1,427
Total purchase price plus liabilities assumed	$	6,243
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)		1,971
Total fair value of assets acquired	$	6,243

See Note 19 for unaudited pro forma information concerning the Anderson acquisition and the Mitchell merger.

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.

PennzEnergy Merger

Devon closed its merger with PennzEnergy Company ("PennzEnergy") on August 17, 1999. The merger was accounted for using the purchase method of accounting for business combinations. Accordingly, the accompanying statement of operations for 1999 includes the effects of PennzEnergy operations since August 17, 1999.

Devon issued approximately 22 million shares of its common stock to the former stockholders of PennzEnergy. In addition, Devon assumed long-term debt and other obligations totaling approximately $2.3 billion on August 17, 1999.

Additionally, $347 million of deferred taxes were created as a result of the merger. Due to the tax-free nature of the merger, Devon's tax basis in the assets acquired and liabilities assumed are the same as PennzEnergy's tax basis. The $347 million of deferred taxes recorded represent the deferred tax effect of the differences between the fair values assigned by Devon for financial reporting purposes to the former PennzEnergy assets and liabilities and their bases for income tax purposes.

Snyder Merger

Santa Fe Snyder was formed on May 5, 1999, when the former Santa Fe Energy Resources, Inc. ("Santa Fe") closed its merger with Snyder Oil Corporation ("Snyder"). Because Devon's merger with Santa Fe Snyder was accounted for using the pooling-of-interests method, the accompanying consolidated financial statements are presented as though Devon merged with Snyder in May 1999.

The Snyder merger was accounted for using the purchase method of accounting for business combinations. Accordingly, the accompanying statement of operations for 1999 includes the effects of Snyder's operations since May 5, 1999.

As restated for the Devon-Santa Fe Snyder pooling, each share of Snyder common stock was exchanged for 0.451 shares of Devon common stock. This resulted in the issuance of approximately 15 million shares of Devon stock in the Snyder merger. In addition, the Snyder merger also included the assumption of approximately $219 million of Snyder's long-term debt as of May 5, 1999.

Additionally, $135 million was added to oil and gas properties for deferred taxes created as a result of the Snyder merger. Due to the tax-free nature of the merger, Santa Fe's tax basis in the assets acquired and liabilities assumed were the same as Snyder's tax basis. The $135 million of deferred taxes recorded represent the deferred tax effect of the differences between the fair values assigned by Santa Fe for financial reporting purposes to the former Snyder assets and liabilities and their bases for income tax purposes.

3. SAN JUAN BASIN TRANSACTION

At the beginning of 1995, Devon entered into a transaction (the "San Juan Basin Transaction") involving a volumetric production payment and a repurchase option. The San Juan Basin Transaction allowed Devon to monetize tax credits earned from certain of its coal seam gas production in the San Juan Basin. During 2000 and 1999, the San Juan Basin Transaction added approximately $12 million and $8 million, respectively, to Devon's gas revenues.

Under the terms of the San Juan Basin Transaction, Devon had a repurchase option which it could exercise at anytime. Devon exercised the repurchase option effective September 30, 2000. Devon had previously recorded a portion of the quarterly cash payments received pursuant to the San Juan Basin Transaction as a repurchase liability based upon the estimated eventual repurchase price. Devon also received cash payments in exchange for agreeing not to exercise its repurchase option for specific periods of time prior to 2000. These payments were also added to the repurchase liability. As a result, in addition to the cash flow recorded as revenues described in the previous paragraph, Devon also received $17 million in 1999 which was added to the repurchase liability. The actual repurchase price as of September 30, 2000, was approximately $36 million.

4. SUPPLEMENTAL CASH FLOW INFORMATION

Cash payments for interest in 2001, 2000 and 1999 were approximately $118 million, $155 million and $116 million, respectively. Cash payments for federal, state and foreign income taxes in 2001, 2000 and 1999 were approximately $192 million, $82 million and $16 million, respectively.

The 2001 Anderson acquisition and the 1999 PennzEnergy merger and Snyder merger involved non-cash consideration as presented below:

	2001	1999
	(IN MILLIONS)	
Value of common stock issued	$ —	1,130
Value of preferred stock issued	—	150
Employee stock options assumed	—	18
Liabilities assumed	1,303	2,259
Deferred tax liability created	1,427	475
Fair value of assets acquired with non-cash consideration	$ 2,730	4,032

During the fourth quarter of 1999, substantially all of the 6.5% Trust Convertible Preferred Securities were converted to Devon common stock (see Note 9).

5. ACCOUNTS RECEIVABLE

The components of accounts receivable included the following:

	DECEMBER 31, 2001	2000	1999
	(IN MILLIONS)		
Oil, gas and natural gas liquids revenue accruals	$ 323	438	218
Joint interest billings	108	123	67
Other	110	41	35
	541	602	320
Allowance for doubtful accounts	(4)	(4)	(4)
Net accounts receivable	$ 537	598	316

6. PROPERTY AND EQUIPMENT

Property and equipment included the following:

	DECEMBER 31, 2001	2000	1999
	(IN MILLIONS)		
Oil and gas properties:			
Subject to amortization	$ 13,266	9,170	8,126
Not subject to amortization:			
Acquired in 2001	1,638	—	—
Acquired in 2000	74	74	—
Acquired in 1999	116	122	135
Acquired prior to 1999	111	119	167
Accumulated depreciation, depletion and amortization	(6,481)	(4,752)	(4,130)
Net oil and gas properties	8,724	4,733	4,298
Other property and equipment	393	224	165
Accumulated depreciation and amortization	(89)	(47)	(39)
Net other property and equipment	304	177	126
Property and equipment, net of accumulated depreciation, depletion and amortization	$ 9,028	4,910	4,424

The costs not subject to amortization relate to unproved properties, none of which are individually significant. Subject to industry conditions, evaluation of these properties 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, 2001	2000	1999
	(IN MILLIONS)		
Depreciation, depletion and amortization of oil and gas properties	$ 838	663	390
Depreciation and amortization of other property and equipment	30	23	14
Amortization of other assets	8	7	2
Total	$ 876	693	406

7. LONG-TERM DEBT AND RELATED EXPENSES

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

	DECEMBER 31, 2001	2000	1999
	(IN MILLIONS)		
Borrowings under credit facilities with banks	$ 50	147	645
Commercial paper borrowings	75	—	—
$3 billion term loan credit facility	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	(111)	—	—
Zero coupon convertible senior debentures exchangeable into shares of Devon Energy Corp. common stock, 3.875% due June 27, 2020	374	360	—
Other debentures:			
10.25% due November 1, 2005	236	250	250
10.125% due November 15, 2009	177	200	200
7.875% due September 30, 2031	1,250	—	—
Net premium on debentures	6	33	37
Senior notes:			
8.05% due June 15, 2004	125	125	125
7.25% due July 18, 2005	110	—	—
6.76% due July 19, 2005	—	—	75
7.42% due October 1, 2005	23	—	—
7.57% due October 4, 2005	31	—	—
6.55% due August 2, 2006	126	—	—
8.75% due June 15, 2007	175	175	175
6.79% due March 2, 2009	—	—	150
6.75% due March 15, 2011	400	—	—
6.875% due September 30, 2011	1,750	—	—
Net discount on notes	(14)	(1)	(1)
	6,589	2,049	2,416
Less amount classified as current	—	—	—
Long-term debt	$ 6,589	2,049	2,416

Maturities of long-term debt as of December 31, 2001, excluding the $119 million of discounts net of premiums, are as follows (in millions):

2002	$ —
2003	—
2004	358
2005	775
2006	689
2007 and thereafter	4,886
Total	$ 6,708

Credit Facilities With Banks

On August 13, 2001, Devon renewed its unsecured long-term credit facilities aggregating $1 billion (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 B facility can be increased to as high as $625 million and reduced to as low as $425 million by reallocating the amount available between the Tranche B facility and the Canadian Facility. The Tranche A facility matures on October 15, 2004. Devon may borrow funds under the Tranche B facility until August 12, 2002 (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. Debt borrowed under the Tranche B facility matures two years and one day following the end of the Tranche B Revolving Period.

Devon may borrow funds under the $275 million Canadian Facility until August 12, 2002 (the “Canadian Facility Revolving Period”). As disclosed in the prior paragraph, the Canadian Facility can be increased to as high as $375 million and reduced to as low as $175 million by reallocating the amount available between the Tranche B facility and the Canadian Facility. Devon may request that the Canadian Facility Revolving Period be extended an additional 364 days by notifying the agent bank of such request between 45 and 90 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 semi-annual 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.

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, and are tied to margins determined by Devon’s corporate credit ratings. Devon may also elect to borrow at the prime rate. The Credit Facilities provide for an annual facility fee of $0.9 million that is payable quarterly. The weighted average interest rate on the $50 million and $147 million outstanding under the Credit Facilities at December 31, 2001 and 2000, was 4.8% and 6.1%, respectively. The average interest rate on bank debt outstanding under the previous facilities at December 31, 1999 was 6.8%.

The agreements governing the Credit Facilities contain certain covenants and restrictions, including a maximum debt-to-capitalization ratio. At December 31, 2001, Devon was in compliance with such covenants and restrictions.

Commercial Paper

On August 29, 2000, Devon entered into a commercial paper program. Devon may borrow up to $725 million under the commercial paper program. Total borrowings under the U.S. Facility and the commercial paper program may not exceed $725 million. The commercial paper borrowings may have terms of up to 365 days and bear interest at rates agreed to at the time of the borrowing. The interest rate is based on a standard index such as the Federal Funds Rate, London Interbank Offered Rate (LIBOR), or the money market rate as found on the commercial paper market. As of December 31, 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%).

The interest rates will include a margin determined by Devon’s long-term senior unsecured debt rating for borrowings made subsequent to June 17, 2002. Prior to that time, the margin for borrowings based on LIBOR will be an additional 100 basis points. Based on LIBOR rates as of December 31, 2001, Devon’s average interest rate was 2.9%. In addition, Devon incurred an availability fee on the daily average unused lending commitments through the date of the Mitchell closing on January 24, 2002, equal to a percentage determined by Devon’s long-term senior unsecured debt rating.

Prior to December 31, 2001, Devon used proceeds of $1 billion from borrowings on this 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.

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

YEAR	(IN MILLIONS)
2002	$ —
2003	—
2004	232
2005	1,200
2006	1,600
Total	$ 3,032

The terms of this facility also provide that voluntary prepayments of the debt may be applied, at Devon’s option, to the earliest scheduled maturities first. For example, if Devon were to prepay a portion of the $3 billion of debt with proceeds from property sales or other cash sources, the amount of the prepayment would reduce, if so elected by Devon, the amounts otherwise due first in 2004, then 2005 and finally 2006.

This credit facility contains certain covenants and restrictions, including a maximum allowed debt-to-capitalization ratio as defined in the credit facility. At December 31, 2001, 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 are callable beginning August 15, 2000, initially at 104.0% of principal and at prices declining to 100.5% of principal on or after August 15, 2007. The exchangeable debentures are exchangeable at the option of the holders at any time prior to maturity, unless previously redeemed, for shares of ChevronTexaco Corporation common stock. In lieu of delivering ChevronTexaco Corporation common stock, Devon may, at its option, pay to any holder an amount of cash equal to the market value of the ChevronTexaco Corporation 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 Corporation common stock.

As of December 31, 2001, Devon beneficially owned approximately seven million shares of ChevronTexaco Corporation 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 Corporation 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 Corporation 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. 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.

Debt Securities

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 1.76%.

Interest on the debt securities will be payable by Devon Financing semiannually on March 30 and September 30 of each year, beginning on March 30, 2002. The indenture governing the debt securities limits both Devon Financing's and Devon's ability to incur liens or enter into mergers or consolidations, or transfer all or substantially all of their respective assets, unless the successor company assumes Devon Financing's or Devon's obligations under the indenture.

Other Debentures

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 a loss on the early retirement of debt of $5 million related to this repurchase.

Senior Notes

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.

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

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

In connection with the Snyder merger, Devon assumed Snyder's $175 million of 8.75% notes due in 2007. The notes are redeemable by Devon on or after June 15, 2002, initially at 104.375% of principal and at prices declining to 100% of principal on or after June 15, 2005. The notes are general unsecured obligations of Devon. 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 thirty nor more than sixty days notice, as a whole or in part, at the option of Devon at a redemption price equal to the sum of (i) 100% of the principal amount thereof, (ii) the applicable make-whole premium as determined by an independent investment banker and (iii) accrued and unpaid interest. The notes are general unsecured obligations of Devon. The indentures for these notes include covenants that restrict the ability of Devon SFS Operating, Inc., a wholly-owned subsidiary of Devon, to take certain actions, including the ability to incur additional indebtedness and to pay dividends or repurchase capital stock.

Interest Expense

Following are the components of interest expense for the years 2001, 2000 and 1999:

	YEAR ENDED DECEMBER 31,		
	2001	2000	1999
		(IN MILLIONS)	
Interest based on debt outstanding	$ 200	157	108
Accretion (amortization) of debt discount (premium), net	10	(4)	(1)
Facility and agency fees	1	3	2
Amortization of capitalized loan costs	3	2	2
Capitalized interest	(3)	(3)	(2)
Loss on debt retirement	7	—	—
Other	2	—	—
Total interest expense	$ 220	155	109

Effects of Changes in Foreign Currency Exchange Rates

The 6.75% fixed-rate senior notes referred to in the first table of this note are payable by Devon Canada, a wholly-owned subsidiary of Devon. However, the notes are denominated in U.S. dollars. Until their retirement in mid-January 2000, the 6.76% and 6.79% fixed-rate senior notes payable by Devon Canada were also 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 issued 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 declined in 2001 and 2000 and increased in 1999. Therefore, $11 million and $3 million of increased expense was recorded in 2001 and 2000, respectively, and $13 million of reduced expense was recorded in 1999.

8. INCOME TAXES

At December 31, 2001, Devon had the following carryforwards available to reduce future income taxes:

TYPES OF CARRYFOR WARD	YEARS OF EXPIRATION	CARRYFOR WARD AMOUNTS
		(IN MILLIONS)
Net operating loss - U.S. federal	2008 - 2021	$ 22
Net operating loss - various states	2002 - 2014	$ 60
Net operating loss - Canada	2002 - 2008	$ 3
Net operating loss - international	Indefinite	$ 91
Minimum tax credits	Indefinite	$ 118

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 2001, 2000 and 1999 were as follows:

	YEAR ENDED DECEMBER 31,		
	2001	2000	1999
		(IN MILLIONS)	
Earnings (loss) before income taxes:			
U.S	$ 458	872	(313)
Canada	(357)	156	58
International	(17)	114	56
Total	$ 84	1,142	(199)
Current income tax expense:			
U.S. federal	$ 23	107	12
Various states	6	6	3
Canada	8	2	3
Other	34	16	5
Total current tax expense	71	131	23
Deferred income tax expense (benefit):			
U.S. federal	124	152	(119)
Various states	(32)	33	—
Canada	(145)	67	27
Other	12	29	20
Total deferred tax expense (benefit)	(41)	281	(72)
Total income tax expense (benefit)	$ 30	412	(49)

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:

	YEARENDED DECEMBER 31,		
	2001	2000	1999
U.S. statutory tax (benefit) rate	35%	35%	(35)%
Benefit from disposition of certain foreign assets	—	(4)	—
Financial expenses not deductible for income tax purposes	14	1	3
Nonconventional fuel source credits	(23)	(1)	(3)
State income taxes	5	1	1
Taxation on foreign operations	12	2	7
Other	(7)	2	2
Effective income tax (benefit) rate	36%	36%	(25)%

The tax effects of temporary differences that gave rise to significant portions of the deferred tax assets and liabilities at December 31, 2001, 2000 and 1999 are presented below:

	DECEMBER 31,		
	2001	2000	1999
		(IN MILLIONS)	
Deferred tax assets:			
Net operating loss carryforwards	$ 39	123	207
Minimum tax credit carryforwards	118	85	88
Production payments	—	—	21
Long-term debt	6	17	18
Fair value of financial instruments	7	—	—
Other	37	95	51
Total deferred tax assets	207	320	385
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	(2,182)	(687)	(500)
ChevronTexaco Corporation common stock	(213)	(167)	(172)
Other	(11)	(84)	(32)
Total deferred tax liabilities	(2,406)	(938)	(704)
Net deferred tax liability	$ (2,199)	(618)	(319)

As shown in the above table, Devon has recognized $207 million of deferred tax assets as of December 31, 2001. Such amount consists primarily of $157 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 2002 and 2014, Canadian carryforwards which expire primarily between 2002 and 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 2002 and 2010. Such expectation is based upon current estimates of taxable income during this period, considering limitations on the annual utilization of these benefits as set forth by federal 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.

9. TRUST CONVERTIBLE PREFERRED SECURITIES

On July 10, 1996, Devon, through its affiliate Devon Financing Trust, completed the issuance of $149 million of 6.5% trust convertible preferred securities (the "TCP Securities"). Devon Financing Trust issued 2,990,000 shares of the TCP Securities at $50 per share with a maturity date of June 15, 2026. Each TCP Security was convertible at the holder's option into 1.6393 shares of Devon common stock, which equated to a conversion price of $30.50 per share of Devon common stock.

Devon Financing Trust invested the $149 million of proceeds in 6.5% convertible junior subordinated debentures issued by Devon (the "Convertible Debentures"). In turn, Devon used the net proceeds from the issuance of the Convertible Debentures to retire debt outstanding under its credit lines.

On October 27, 1999, Devon issued notice to the holders of the TCP Securities that it was exercising its right to redeem such securities on November 30, 1999. Substantially all of the holders of the TCP Securities elected to exercise their conversion rights instead of receiving the redemption cash value. As a result, all but 950 shares of the TCP Securities were converted into approximately 4.9 million shares of Devon common stock. The redemption price for the 950 shares not converted was $52.275 per share which included a 4.55% premium as required under the terms of the TCP Securities.

Devon owned all the common securities of Devon Financing Trust. As such, the accounts of Devon Financing Trust were included in Devon's consolidated financial statements after appropriate eliminations of intercompany balances and transactions. The distributions on the TCP Securities were recorded as a charge to pre-tax earnings on Devon's consolidated statements of operations, and such distributions were deductible by Devon for income tax purposes.

10. 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.

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.

In late September and early October 1999, Devon received $403 million from the sale of approximately 10 million shares of its common stock in a public offering. The price to the public for these shares was $40.50 per share. Net of underwriters' discount and commissions, Devon received $38.98 per share. Devon paid approximately $1 million of expenses related to the equity offering, and these costs were recorded as reductions of additional paid-in capital.

As discussed in Note 2, there were approximately 22 million shares of Devon common stock issued on August 17, 1999, in connection with the PennzEnergy merger. Also, there were 16 million Exchangeable Shares issued on December 10, 1998, in connection with the Northstar Energy Corporation combination. As of year-end 2001, 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.

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, 2001, 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, 2001, there were 63,000 and 320,860 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, plus 10% if the grantee owns or controls more than 10% of the total voting stock of Devon prior to the 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, 2001, there were 5,274,235 options outstanding under the 1997 Plan. There were 3,745,334 options available for future grants as of December 31, 2001.

In addition to the stock options outstanding under the 1988 Plan, 1993 Plan and 1997 Plan, there were approximately 1,053,807, 1,410,158 and 62,270 stock options outstanding at the end of 2001 that were assumed as part of the Santa Fe Snyder merger, the PennzEnergy merger and the Northstar combination, respectively. Santa Fe Snyder, PennzEnergy and Northstar had granted these options prior to the Santa Fe Snyder merger, the PennzEnergy merger and the Northstar combination. As part of the Santa Fe Snyder merger, the PennzEnergy merger and the Northstar combination, the options were assumed by Devon and converted to Devon options at the exchange rate of 0.22, 0.4475 and 0.235 Devon options for each Santa Fe Snyder, PennzEnergy and Northstar option, respectively.

A summary of the status of Devon’s stock option plans as of December 31, 1999, 2000 and 2001, and changes during each of the years then ended, is presented below.

	OPTIONS OUTSTANDING		OPTIONS EXERCISABLE	
	NUMBER OUTSTANDING	EXERCISE PRICE	NUMBER EXERCISABLE	WEIGHTED AVERAGE EXERCISE PRICE
BALANCE AT DECEMBER 31, 1998	5,520,656	$ 31.768	4,079,125	$ 30.479
Options granted	1,564,108	$ 31.736		
Options assumed in the PennzEnergy merger	2,081,894	$ 55.643		
Options assumed in the Snyder merger	979,220	$ 35.182		
Options exercised	(1,139,231)	$ 28.509		
Options forfeited	(452,746)	$ 36.369		
BALANCE AT DECEMBER 31, 1999	8,553,901	$ 38.202	7,063,983	$ 39.547
Options granted	1,624,800	$ 51.430		
Options exercised	(2,488,756)	$ 33.106		
Options forfeited	(333,991)	$ 60.354		
BALANCE AT DECEMBER 31, 2000	7,355,954	$ 41.843	6,024,796	$ 40.718
Options granted	2,600,650	$ 62.808		
Options exercised	(1,504,691)	$ 31.133		
Options forfeited	(267,583)	$ 62.774		
BALANCE AT DECEMBER 31, 2001	8,184,330	$ 41.089	5,515,958	$ 41.934

The weighted average fair values of options granted during 2001, 2000 and 1999 were $13.17, $28.73 and $12.80, 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 2001, 2000 and 1999, respectively: risk-free interest rates of 3.8%, 5.5% and 6%; dividend yields of 0.6%, 0.4% and 0.5%; expected lives of five, five and five years; and volatility of the price of the underlying common stock of 42.2%, 40% and 35.2%.

The following table summarizes information about Devon's stock options which were outstanding, and those which were exercisable, as of December 31, 2001:

	OPTIONS OUTSTANDING			OPTIONS EXERCISABLE	
RANGE OF EXERCISE PRICES	NUMBER OUTSTANDING	WEIGHTED AVERAGE REMAINING LIFE	WEIGHTED AVERAGE EXERCISE PRICE	NUMBER EXERCISABLE	WEIGHTED AVERAGE EXERCISE PRICE
\$ 8.375-\$26.501	442,204	2.38 Years	\$ 23.014	442,204	\$ 23.014
\$28.830-\$33.381	1,314,346	5.29 Years	\$ 30.726	1,239,114	\$ 30.713
\$34.375-\$39.773	3,445,957	7.04 Years	\$ 35.308	1,569,779	\$ 35.818
\$40.190-\$49.950	454,980	4.01 Years	\$ 45.941	444,996	\$ 45.916
\$50.142-\$59.813	2,028,308	6.66 Years	\$ 53.177	1,329,064	\$ 53.865
\$60.150-\$89.660	498,535	5.36 Years	\$ 70.788	490,801	\$ 70.954
	8,184,330	6.15 Years	\$ 41.089	5,515,958	\$ 41.934

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 2001, 2000 and 1999 pro forma net earnings (loss) and pro forma net earnings (loss) per share would have differed from the amounts actually reported as shown in the following table. The pro forma amounts shown below do not include the effects of stock options granted prior to January 1, 1995.

	YEAR ENDED DECEMBER 31,		
	2001	**2000**	**1999**
	(IN MILLIONS, EXCEPT PER SHARE AMOUNTS)		
Net earnings (loss) available to common shareholders:			
As reported	\$ 93	720	(158)
Pro forma	\$ 79	702	(173)
Net earnings (loss) per share available to common shareholders:			
As reported:			
Basic	\$ 0.73	5.66	(1.68)
Diluted	\$ 0.72	5.50	(1.68)
Pro forma:			
Basic	\$ 0.62	5.51	(1.85)
Diluted	\$ 0.61	5.36	(1.85)

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 ten business days after a) an announcement that a person has acquired, or obtained the right to acquire, 15% or more of the voting shares outstanding, or b) commencement of a tender or exchange offer that could result in a person owning 15% or more of the voting shares outstanding.

Each right entitles its holder (except a holder who is the acquiring person) to purchase either (a) 1/100 of a share of Series A Preferred Stock for \$75.00, subject to adjustment or, (b) Devon Common Stock with a value equal to twice the exercise price of the right, subject to adjustment to prevent dilution. In the event of certain merger or asset sale transactions with another party or transactions which would increase the equity ownership of a shareholder who then owned 15% or more of Devon, each Devon right will entitle its holder to purchase securities of the merging or acquiring party with a value equal to twice the exercise price of the right.

The rights, which have no voting power, expire on April 16, 2005. The rights may be redeemed by Devon for \$.01 per right until the rights become exercisable.

11. FINANCIAL INSTRUMENTS

The following table presents the carrying amounts and estimated fair values of Devon's financial instruments at December 31, 2001, 2000 and 1999.

	2001		2000		1999	
	CARRYING AMOUNT	FAIR VALUE	CARRYING AMOUNT	FAIR VALUE	CARRYING AMOUNT	FAIR VALUE
			(IN MILLIONS)			
Investments	$ 644	644	606	606	634	634
Oil and gas price hedge agreements	$ 225	225	—	(58)	—	(10)
Interest rate swap agreements	$ (9)	(9)	—	—	—	—
Electricity hedge agreements	$ (12)	(12)	—	—	—	—
Foreign exchange hedge agreements	$ (4)	(4)	—	(1)	—	(3)
Embedded option in exchangeable debentures	$ (34)	(34)	—	—	—	—
Long-term debt (including current portion)	$ (6,589)	(6,699)	(2,049)	(2,050)	(2,416)	(2,400)

The following methods and assumptions were used to estimate the fair values of the financial instruments in the above table. None of Devon's financial instruments are held for trading purposes. 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, 2001, 2000 and 1999.

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, 2002 are set forth in the following tables.

Price Swaps Through various price swaps, Devon has fixed the price it will receive on a portion of its oil and natural gas production in 2002, 2003 and 2004. The following tables include information on this production. Where necessary, the prices have been adjusted for certain transportation costs that are netted against the price recorded by Devon, and the price has also been adjusted for the Btu content of the gas production that has been hedged.

OIL PRODUCTION		
YEAR	BBLS/DAY	PRICE/BBL
2002	26,350	$ 23.27

GAS PRODUCTION		
YEAR	MCF/DAY	PRICE/MCF
2002	242,128	$ 2.99
2003	99,905	$ 3.35
2004	4,164	$ 2.36

Costless Price Collars Devon has also entered into costless price collars that set a floor and ceiling price for a portion of its 2002 and 2003 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 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 table are weighted averages of all the various collars.

	OIL PRODUCTION		
YEAR	BBLS/DAY	FLOOR PRICE PER BBL	CEILING PRICE PER BBL
2002	20,000	$ 23.00	$ 28.19

	GAS PRODUCTION		
YEAR	MMBTU/DAY	FLOOR PRICE PER MMBTU	CEILING PRICE PER MMBTU
2002	442,574	$ 3.34	$ 6.37
2003	345,000	$ 3.20	$ 4.19

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 6.2% on $132 million of debt in 2002, 6.3% on $97 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.

Foreign Currency Exchange Rate Swaps Devon assumed certain foreign currency exchange rate swaps in the Anderson acquisition. These swaps require Devon to sell $30 million and $12 million at average Canadian-to-U.S. exchange rates of $0.680 and $0.676, and buy the same amount of dollars at the floating exchange rate, in 2002 and 2003, respectively.

12. RETIREMENT PLANS

Devon has non-contributory defined benefit retirement plans (the "Basic Plans") which 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. Devon's funding policy is to contribute annually the maximum amount that can be deducted for federal income tax purposes. Rights to amend or terminate the Basic Plans are retained by Devon.

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.

In 2000, Devon established a defined benefit postretirement plan, which is unfunded, and covers substantially all current employees including former Santa Fe Snyder and PennzEnergy employees who remained with Devon. Additionally, Devon assumed responsibility for the PennzEnergy sponsored defined benefit postretirement plans, which are unfunded. The plans provide medical and 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 for 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, 2001, 2000 and 1999.

	PENSION BENEFITS			OTHER POSTRETIREMENT BENEFITS		
	2001	2000	1999	2001	2000	1999
	(IN MILLIONS)					
Change in benefit obligation:						
Benefit obligation at beginning of year	$ 165	156	64	$ 32	38	8
Service cost	5	7	5	–	1	1
Interest cost	13	11	6	2	2	1
Participant contributions	–	–	–	1	–	–
Amendments	5	4	–	(1)	(2)	–
Mergers and acquisitions	16	–	88	–	–	29
Special termination benefits	3	–	–	–	–	–
Settlement payments	(4)	–	–	–	–	–
Curtailment gain	(1)	(3)	–	–	–	–
Actuarial (gain) loss	17	(3)	(3)	4	(3)	1
Benefits paid	(9)	(7)	(4)	(5)	(4)	(2)
Benefit obligation at end of year	210	165	156	33	32	38
Change in plan assets:						
Fair value of plan assets at beginning of year	155	158	42	–	–	–
Actual return on plan assets	(9)	3	15	–	–	–
Mergers and acquisitions	17	–	104	–	–	–
Employer contributions	6	1	1	4	4	2
Participant contributions	–	–	–	1	–	–
Settlement payments	(4)	–	–	–	–	–
Administrative expenses	–	–	–	–	–	–
Benefits paid	(9)	(7)	(4)	(5)	(4)	(2)
Fair value of plan assets at end of year	156	155	158	–	–	–
Funded status	(54)	(10)	2	(33)	(32)	(38)
Unrecognized net actuarial (gain) loss	35	10	(3)	2	(2)	1
Unrecognized prior service cost	6	1	2	(1)	(1)	–
Unrecognized net transition (asset) obligation	–	(6)	–	–	1	2
Net amount recognized	$ (13)	(5)	1	$ (32)	(34)	(35)
The net amounts recognized in the consolidated balance sheets consist of:						
(Accrued) prepaid benefit cost	$ (13)	(5)	1	$ (32)	(34)	(35)
Additional minimum liability	(33)	(1)	(3)	–	–	–
Intangible asset	5	1	1	–	–	–
Accumulated other comprehensive loss	28	–	2	–	–	–
Net amount recognized	$ (13)	(5)	1	$ (32)	(34)	(35)
Assumptions:						
Discount rate	7.10%	7.65%	7.34%	7.15%	7.65%	7.32%
Expected return on plan assets	8.27%	8.50%	8.37%	N/A	N/A	N/A
Rate of compensation increase	4.88%	5.00%	4.88%	5.00%	5.00%	4.75%

The benefit obligation for the defined benefit pension plans with benefit obligations in excess of assets was $201 million as of December 31, 2001. The plan assets for these plans at December 31, 2001 totaled $138 million.

Net periodic benefit cost included the following components:

	PENSION BENEFITS			OTHER POSTRETIREMENT BENEFITS		
	2001	2000	1999	2001	2000	1999
	(IN MILLIONS)					
Service cost	$ 5	7	5	$ –	1	1
Interest cost	13	11	6	2	2	1
Expected return on plan assets	(13)	(13)	(7)	–	–	–
Amortization of prior service cost	1	–	–	–	–	–
Recognized net actuarial (gain) loss	1	–	–	–	–	–
Net periodic benefit cost	$ 7	5	4	$ 2	3	2

For measurement purposes, a 9% annual rate of increase in the per capita cost of covered health care benefits was assumed in 2001. The rate was assumed to decrease on a pro-rata basis annually to 5% in the year 2005 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 INCREASE	ONE-PERCENTAGE POINT DECREASE
	(IN MILLIONS)	
Effect on total of service and interest cost components for 2001	$ –	$ –
Effect on year-end 2001 post-retirement benefit obligation	$ 1	$ (1)

Devon has incurred certain post-employment benefits to former or inactive employees who are not retirees. These benefits include salary continuance, severance and disability health care and life insurance which are accounted for under SFAS No. 112, *Employer's Accounting for Post-Employment Benefits*. The accrued post-employment benefit liability was approximately $7 million, $13 million and $3 million at the end of 2001, 2000 and 1999, respectively.

Devon has a 401(k) Incentive Savings Plan which covers all domestic employees. At its discretion, Devon may match a certain percentage of the employees' contributions to the plan. The matching percentage is determined annually by the Board of Directors. Devon's matching contributions to the plan were $5 million, $5 million and $4 million for the years ended December 31, 2001, 2000 and 1999, respectively.

Devon has defined contribution plans for its Canadian employees. Devon contributes between 6% and 10% of the employee's base compensation, depending upon the employee's 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 an amount equal to 2% of the base salary of each employee. The employees may elect to contribute up to 4% of their salary. If such employee contributions are made, they are matched by additional Devon contributions.

During the years 2001, 2000 and 1999, Devon's combined contributions to the Canadian defined contribution plan and the Canadian savings plan were $3 million, $2 million and $2 million, respectively.

13. COMMITMENTS AND CONTINGENCIES

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

Environmental Matters

Devon is subject to certain laws and regulations relating to environmental remediation activities associated with past operations, such as the Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA") and similar state statutes. In response to liabilities associated with these activities, accruals have been established when reasonable estimates are possible. Such accruals primarily include estimated costs associated with remediation. Devon has not used discounting in determining its accrued liabilities for environmental remediation, and no 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 the PennzEnergy merger 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, 2001, Devon's consolidated balance sheet included $8 million of accrued liabilities, reflected in "Other liabilities," for environmental remediation. 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) the availability of defenses to liability, including the availability of the "petroleum exclusion" under CERCLA and similar state laws, and/or (ii) Devon's current belief that its share of wastes at a particular site is or will be viewed by the Environmental Protection Agency or other PRPs as being de minimis. 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.

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, 2001:

YEAR ENDING DECEMBER 31,	(IN MILLIONS)
2002	$ 21
2003	20
2004	16
2005	14
2006	11
Thereafter	14
Total minimum lease payments required	$ 96

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

	(IN MILLIONS)
2001	$ 17
2000	$ 19
1999	$ 24

Santa Fe Energy Trust

The Santa Fe Energy Trust (the “Trust”) was formed in 1992 to hold 6.3 million Depository Units, each consisting of beneficial ownership of one unit of undivided interest in the Trust and a $20 face amount beneficial ownership interest in a $1,000 face amount zero coupon U.S. Treasury obligation maturing on or about February 15, 2008, when the Trust will be liquidated. The assets of the Trust consist of certain oil and gas properties conveyed to it by Santa Fe Snyder.

For any calendar quarter ending on or prior to December 31, 2002, the Trust will receive additional support payments from Devon to the extent that the Trust needs such payments to distribute $0.38 per Depository Unit per quarter. The source of such support payments is limited to Devon’s remaining royalty interest in certain of the properties conveyed to the Trust. The aggregate amount of the additional royalty payments (net of any amounts recouped) is limited to $19 million on a revolving basis. If such support payments are made, certain proceeds otherwise payable to the Trust in subsequent quarters may be reduced to recoup the amount of such support payments. Through the end of 2001, the Trust had received support payments totaling $4 million and Devon had recouped all such payments.

Depending on various factors, such as sales volumes and prices and the level of operating costs and capital expenditures incurred, proceeds payable to the Trust with respect to operations in subsequent quarters may not be sufficient to make the required quarterly distributions. In such instances, Devon would be required to make support payments.

At December 31, 2001, 2000 and 1999, accounts payable as shown on the accompanying consolidated balance sheets included $3 million, $4 million and $3 million, respectively, due to the Trust.

14. 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 lower of cost or fair value of unproved properties. The ceiling is imposed 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 2001 and 1999, Devon reduced the carrying value of its oil and gas properties by $916 and $476 million, respectively, due to the full cost ceiling limitations. The after-tax effect of these reductions in 2001 and 1999 were $556 million and $310 million, respectively. The following table summarizes these reductions by country.

YEAR ENDED DECEMBER 31,

	2001		1999	
	GROSS	NET OF TAXES	GROSS	NET OF TAXES
	(IN MILLIONS)			
United States	$ 449	281	464	302
Canada	434	252	–	–
Egypt	33	23	–	–
China	–	–	12	8
Total	$ 916	556	476	310

The 2001 domestic and Canadian reductions were 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 indicative of the true fair value of the reserves. 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 year-end 2001 prices used to calculate the ceiling. The reduction in Egypt was the result of high finding and development costs and negative revisions to proved reserves.

The 1999 domestic reduction was primarily the result of lower prices. The oil and gas properties added from the Snyder acquisition were recorded at fair values that were based on expected future oil and gas prices higher than the quarterly prices used to calculate the ceiling. The reduction in China was the result of high finding and development costs.

Additionally, during 2001, Devon elected to discontinue 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 an $87 million charge associated with the impairment of these properties. The after-tax effect of this reduction was $69 million.

15. OIL AND GAS OPERATIONS

Costs Incurred

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

	TOTAL		
	YEAR ENDED DECEMBER 31,		
	2001	2000	1999
	(IN MILLIONS)		
Property acquisition costs:			
Proved, excluding deferred income taxes	$ 2,975	291	3,002
Deferred income taxes	84	–	132
Total proved, including deferred income taxes	$ 3,059	291	3,134
Unproved, excluding deferred income taxes:			
Business combinations	1,433	–	84
Other acquisitions	183	55	40
Deferred income taxes	27	–	–
Total unproved, including deferred income taxes	$ 1,643	55	124
Exploration costs	$ 356	213	158
Development costs	$ 978	636	336

	DOMESTIC		
	YEAR ENDED DECEMBER 31,		
	2001	2000	1999
	(IN MILLIONS)		
Property acquisition costs:			
Proved, excluding deferred income taxes	$ 292	177	2,670
Deferred income taxes	79	–	132
Total proved, including deferred income taxes	$ 371	177	2,802
Unproved, excluding deferred income taxes:			
Business combinations	–	–	82
Other acquisitions	158	35	28
Deferred income taxes	27	–	–
Total unproved, including deferred income taxes	$ 185	35	110
Exploration costs	$ 166	117	88
Development costs	$ 726	466	228

CANADA

	YEAR ENDED DECEMBER 31,		
	2001	2000	1999
	(IN MILLIONS)		
Property acquisition costs:			
Proved, excluding deferred income taxes	$ 2,621	70	29
Deferred income taxes	5	–	–
Total proved, including deferred income taxes	$ 2,626	70	29
Unproved, excluding deferred income taxes:			
Business combinations	1,433	–	–
Other acquisitions	24	17	9
Deferred income taxes	–	–	–
Total unproved, including deferred income taxes	$ 1,457	17	9
Exploration costs	$ 126	55	37
Development costs	$ 168	57	30

	INTERNATIONAL		
	YEAR ENDED DECEMBER 31,		
	2001	2000	1999
	(IN MILLIONS)		
Property acquisition costs:			
Proved, excluding deferred income taxes	$ 62	44	303
Deferred income taxes	–	–	–
Total proved, including deferred income taxes	$ 62	44	303
Unproved, excluding deferred income taxes:			
Business combinations	–	–	2
Other acquisitions	1	3	3
Deferred income taxes	–	–	–
Total unproved, including deferred income taxes	$ 1	3	5
Exploration costs	$ 64	41	33
Development costs	$ 84	113	78

Pursuant to the full cost method of accounting, Devon capitalizes certain of its general and administrative expenses which are related to property acquisition, exploration and development activities. Such capitalized expenses, which are included in the costs shown in the preceding tables, were $77 million, $62 million and $29 million in the years 2001, 2000 and 1999, 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. 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 and gas sales after deducting costs, including depreciation, depletion and amortization and after giving effect to permanent differences.

	TOTAL		
	YEAR ENDED DECEMBER 31,		
	2001	2000	1999
	(IN MILLIONS, EXCEPT PER EQUIVALENT BARREL AMOUNTS)		
Oil, gas and natural gas liquids sales	$ 2,980	2,718	1,257
Production and operating expenses	(731)	(597)	(378)
Depreciation, depletion and amortization	(838)	(663)	(390)
Amortization of goodwill	(34)	(41)	(16)
Reduction of carrying value of oil and gas properties	(1,003)	–	(476)
Income tax expense	(159)	(572)	(25)
Results of operations for oil and gas producing activities	$ 215	845	(28)
Depreciation, depletion and amortization per equivalent barrel of production	$ 6.20	5.48	4.46

	DOMESTIC		
	YEAR ENDED DECEMBER 31,		
	2001	2000	1999
	(IN MILLIONS, EXCEPT PER EQUIVALENT BARREL AMOUNTS)		
Oil, gas and natural gas liquids sales	$ 2,260	2,168	892
Production and operating expenses	(512)	(463)	(254)
Depreciation, depletion and amortization	(615)	(541)	(294)
Amortization of goodwill	(34)	(41)	(16)
Reduction of carrying value of oil and gas properties	(449)	–	(464)
Income tax (expense) benefit	(267)	(446)	38
Results of operations for oil and gas producing activities	$ 383	677	(98)
Depreciation, depletion and amortization per equivalent barrel of production	$ 6.47	5.73	4.98

CANADA

		YEAR ENDED DECEMBER 31,		
		2001	2000	1999
		(IN MILLIONS, EXCEPT PER EQUIVALENT BARREL AMOUNTS)		
Oil, gas and natural gas liquids sales	$	481	303	204
Production and operating expenses		(137)	(64)	(63)
Depreciation, depletion and amortization		(164)	(64)	(64)
Reduction of carrying value of oil and gas properties		(434)	–	–
Income tax benefit (expense)		99	(80)	(38)
Results of operations for oil and gas producing activities	$	(155)	95	39
Depreciation, depletion and amortization per equivalent barrel of production	$	5.74	4.05	3.56

		INTERNATIONAL		
		YEAR ENDED DECEMBER 31,		
		2001	2000	1999
		(IN MILLIONS, EXCEPT PER EQUIVALENT BARREL AMOUNTS)		
Oil, gas and natural gas liquids sales	$	239	247	161
Production and operating expenses		(82)	(70)	(61)
Depreciation, depletion and amortization		(59)	(58)	(32)
Amortization of goodwill		–	–	–
Reduction of carrying value of oil and gas properties		(120)	–	(12)
Income tax benefit (expense)		9	(46)	(25)
Results of operations for oil and gas producing activities	$	(13)	73	31
Depreciation, depletion and amortization per equivalent barrel of production	$	5.08	5.38	3.06

16. 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.”

Quantities of Oil and Gas Reserves

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, 2001. Approximately 67%, 80% and 98%, of the respective year-end 2001, 2000 and 1999 domestic proved reserves were calculated by the independent petroleum consultants of LaRoche Petroleum Consultants, Ltd. and Ryder Scott Company Petroleum Consultants. The remaining percentages of domestic reserves are based on Devon's own estimates. Approximately 43% of the year-end 2001 Canadian proved reserves were calculated by the independent petroleum consultants of Paddock Lindstrom & Associates and Gilbert Laustsen Jung Associates, Ltd. The remaining percentage of Canadian reserves are based on Devon’s own estimates. All of the year-end 2000 and 1999 Canadian proved reserves were calculated by the independent petroleum consultants Paddock Lindstrom & Associates. All of the international proved reserves other than Canada as of December 31, 2001, 2000 and 1999 were calculated by the independent petroleum consultants of Ryder Scott Company Petroleum Consultants.

	TOTAL		
	OIL (MMBBLS)	GAS (BCF)	NATURAL GAS LIQUIDS (MMBBLS)
Proved reserves as of December 31, 1998	235	1,477	33
Revisions of estimates	12	7	3
Extensions and discoveries	13	406	4
Purchase of reserves	273	1,418	33
Production	(32)	(304)	(5)
Sale of reserves	(5)	(54)	–
Proved reserves as of December 31, 1999	496	2,950	68
Revisions of estimates	(4)	99	3
Extensions and discoveries	34	601	6
Purchase of reserves	24	301	–
Production	(43)	(426)	(7)
Sale of reserves	(48)	(67)	(8)
Proved reserves as of December 31, 2000	459	3,458	62
Revisions of estimates	(14)	(315)	6
Extensions and discoveries	31	579	9
Purchase of reserves	166	2,267	52
Production	(44)	(498)	(8)
Sale of reserves	(12)	(14)	–
Proved reserves as of December 31, 2001	586	5,477	121
Proved developed reserves as of:			
December 31, 1998	180	1,282	19
December 31, 1999	301	2,501	52
December 31, 2000	261	2,631	46
December 31, 2001	324	3,948	88

	DOMESTIC		
	OIL (MMBBLS)	GAS (BCF)	NATURAL GAS LIQUIDS (MMBBLS)
Proved reserves as of December 31, 1998	101	838	16
Revisions of estimates	24	36	3
Extensions and discoveries	2	230	3
Purchase of reserves	143	1,400	33
Production	(18)	(221)	(4)
Sale of reserves	(3)	(8)	–
Proved reserves as of December 31, 1999	249	2,275	51
Revisions of estimates	(3)	101	4
Extensions and discoveries	21	504	5
Purchase of reserves	21	53	–
Production	(29)	(355)	(6)
Sale of reserves	(33)	(57)	(8)
Proved reserves as of December 31, 2000	226	2,521	46
Revisions of estimates	(25)	(262)	7
Extensions and discoveries	12	360	5
Purchase of reserves	15	170	–
Production	(26)	(376)	(6)
Sale of reserves	(11)	(14)	–
Proved reserves as of December 31, 2001	191	2,399	52
Proved developed reserves as of:			
December 31, 1998	93	664	15
December 31, 1999	214	1,960	48
December 31, 2000	192	2,087	42
December 31, 2001	167	1,988	48

	CANADA		
	OIL (MMBBLS)	GAS (BCF)	NATURAL GAS LIQUIDS (MMBBLS)
Proved reserves as of December 31, 1998	39	602	5
Revisions of estimates	(3)	(41)	–
Extensions and discoveries	–	53	–
Purchase of reserves	3	12	–
Production	(5)	(74)	(1)
Sale of reserves	(2)	(46)	–
Proved reserves as of December 31, 1999	32	506	4
Revisions of estimates	3	(6)	–
Extensions and discoveries	3	65	1
Purchase of reserves	3	27	–
Production	(5)	(62)	(1)
Sale of reserves	–	(6)	–
Proved reserves as of December 31, 2000	36	524	4
Revisions of estimates	–	(22)	–
Extensions and discoveries	5	139	2
Purchase of reserves	133	2,097	52
Production	(8)	(113)	(2)
Sale of reserves	–	–	–
Proved reserves as of December 31, 2001	166	2,625	56
Proved developed reserves as of:			
December 31, 1998	33	583	4
December 31, 1999	29	501	4
December 31, 2000	30	508	4
December 31, 2001	124	1,923	40

	INTERNATIONAL		
	OIL (MMBBLS)	GAS (BCF)	NATURAL GAS LIQUIDS (MMBBLS)
Proved reserves as of December 31, 1998	95	37	12
Revisions of estimates	(9)	12	–
Extensions and discoveries	11	123	1
Purchase of reserves	127	6	–
Production	(9)	(9)	–
Sale of reserves	–	–	–
Proved reserves as of December 31, 1999	215	169	13
Revisions of estimates	(4)	4	(1)
Extensions and discoveries	10	32	–
Purchase of reserves	–	221	–
Production	(9)	(9)	–
Sale of reserves	(15)	(4)	–
Proved reserves as of December 31, 2000	197	413	12
Revisions of estimates	11	(31)	(1)
Extensions and discoveries	14	80	2
Purchase of reserves	18	–	–
Production	(10)	(9)	–
Sale of reserves	(1)	–	–
Proved reserves as of December 31, 2001	229	453	13
Proved developed reserves as of:			
December 31, 1998	54	35	–
December 31, 1999	58	40	–
December 31, 2000	39	36	–
December 31, 2001	33	37	–

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, 2001	2000	1999
	(IN MILLIONS)		
Future cash inflows	$ 23,790	40,594	18,495
Future costs:			
Development	(2,228)	(1,635)	(1,507)
Production	(8,424)	(8,198)	(6,271)
Future income tax expense	(3,403)	(9,088)	(1,928)
Future net cash flows	9,735	21,673	8,789
10% discount to reflect timing of cash flows	(4,421)	(9,201)	(4,021)
Standardized measure of discounted future net cash flows	$ 5,314	12,472	4,768

	DOMESTIC DECEMBER 31, 2001	2000	1999
	(IN MILLIONS)		
Future cash inflows	$ 9,861	29,144	11,363
Future costs:			
Development	(793)	(916)	(751)
Production	(3,774)	(5,661)	(3,894)
Future income tax expense	(759)	(6,346)	(1,072)
Future net cash flows	4,535	16,221	5,646
10% discount to reflect timing of cash flows	(1,734)	(6,592)	(2,335)
Standardized measure of discounted future net cash flows	$ 2,801	9,629	3,311

	CANADA DECEMBER 31, 2001	2000	1999
	(IN MILLIONS)		
Future cash inflows	$ 9,011	5,686	1,666
Future costs:			
Development	(922)	(85)	(66)
Production	(3,292)	(616)	(515)
Future income tax expense	(2,006)	(1,967)	(204)
Future net cash flows	2,791	3,018	881
10% discount to reflect timing of cash flows	(1,195)	(1,241)	(321)
Standardized measure of discounted future net cash flows	$ 1,596	1,777	560

	INTERNATIONAL DECEMBER 31, 2001	2000	1999
	(IN MILLIONS)		
Future cash inflows	$ 4,918	5,764	5,466
Future costs:			
Development	(513)	(634)	(690)
Production	(1,358)	(1,921)	(1,862)
Future income tax expense	(638)	(775)	(652)
Future net cash flows	2,409	2,434	2,262
10% discount to reflect timing of cash flows	(1,492)	(1,368)	(1,365)
Standardized measure of discounted future net cash flows	$ 917	1,066	897

Future cash inflows are computed by applying year-end prices (averaging $16.54 per barrel of oil, adjusted for transportation and other charges, $2.28 per Mcf of gas and $13.21 per barrel of natural gas liquids at December 31, 2001) to the year-end quantities of proved reserves, except in those instances where fixed and determinable price changes are provided by contractual arrangements in existence at year-end.

Future development and production costs are computed by estimating the expenditures to be incurred in developing and producing proved oil and gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions. Of the $2.2 billion of future development costs, $532 million, $275 million and $183 million are estimated to be spent in 2002, 2003 and 2004, respectively.

Future development costs include not only development costs, but also future dismantlement, abandonment and rehabilitation costs. Included as part of the $2.2 billion of future development costs are $276 million of future dismantlement, abandonment and rehabilitation costs.

Future income tax expenses are computed by applying the appropriate statutory tax rates to the future pre-tax net cash flows relating to proved reserves, net of the tax basis of the properties involved. The future income tax expenses give effect to permanent differences and tax credits, but do not reflect the impact of future operations.

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

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

	YEAR ENDED DECEMBER 31,		
	2001	2000	1999
		(IN MILLIONS)	
Beginning balance	$ 12,472	4,768	1,414
Sales of oil, gas and natural gas liquids, net of production costs	(2,249)	(2,121)	(880)
Net changes in prices and production costs	(12,130)	9,753	1,737
Extensions, discoveries, and improved recovery, net of future development costs	693	2,742	316
Purchase of reserves, net of future development costs	2,483	618	2,882
Development costs incurred during the period which reduced future development costs	364	183	234
Revisions of quantity estimates	(360)	420	(63)
Sales of reserves in place	(86)	(818)	(78)
Accretion of discount	1,774	581	147
Net change in income taxes	3,406	(4,221)	(929)
Other, primarily changes in timing	(1,053)	567	(12)
Ending balance	$ 5,314	12,472	4,768

17. SEGMENT INFORMATION

Devon manages its business by country. As such, Devon identifies its segments based on geographic areas. Devon has three reportable segments: its operations in the U.S., its operations in Canada, and its international operations outside of North America. Substantially all of these segments' operations involve oil and gas producing activities. Certain information regarding such activities for each segment is included in Notes 15 and 16.

17. SEGMENT INFORMATION (CONTINUED)

Following is certain financial information regarding Devon's segments for 2001, 2000 and 1999. The revenues reported are all from external customers.

	U.S.	CANADA	INTERNATIONAL	TOTAL
		(IN MILLIONS)		
AS OF DECEMBER 31, 2001:				
Current assets	$ 661	192	228	1,081
Property and equipment, net of accumulated depreciation, depletion and amortization	4,051	4,248	729	9,028
Goodwill, net of amortization	209	1,928	69	2,206
Other assets	826	33	10	869
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	51	2,142
Other liabilities	224	20	31	275
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	226	958
Gas sales	1,571	307	12	1,890
Natural gas liquids sales	103	28	1	132
Other	78	8	9	95
Total revenues	2,338	489	248	3,075
COSTS AND EXPENSES				
Lease operating expenses	340	110	81	531
Transportation costs	59	24	–	83
Production taxes	113	3	1	117
Depreciation, depletion and amortization of property and equipment	647	166	63	876
Amortization of goodwill	34	–	–	34
General and administrative expenses	98	15	(2)	111
Expenses related to mergers	–	1	–	1
Interest expense	139	81	–	220
Effects of changes in foreign currency exchange rates	–	11	2	13
Change in fair value of financial instruments	1	1	–	2
Reduction in carrying value of oil and gas properties	449	434	120	1,003
Total costs and expenses	1,880	846	265	2,991
Earnings (loss) before income tax expense (benefit) and cumulative effect of change in accounting principle	458	(357)	(17)	84
INCOME TAX EXPENSE (BENEFIT)				
Current	29	8	34	71
Deferred	92	(145)	12	(41)
Total income tax expense (benefit)	121	(137)	46	30
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	196	5,326

	U.S.	CANADA	INTERNATIONAL	TOTAL
		(IN MILLIONS)		
AS OF DECEMBER 31, 2000:				
Current assets	$ 645	79	210	934
Property and equipment, net of accumulated depreciation, depletion and amortization	3,640	586	684	4,910
Other assets	964	–	52	1,016
Total assets	$ 5,249	665	946	6,860
Current liabilities	449	74	106	629
Long-term debt	1,902	147	–	2,049
Deferred tax liabilities	537	69	21	627
Other liabilities	259	1	18	278
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	236	1,079
Gas sales	1,305	169	11	1,485
Natural gas liquids sales	136	18	–	154
Other	58	5	3	66
Total revenues	2,226	308	250	2,784
COSTS AND EXPENSES				
Lease operating expenses	319	52	70	441
Transportation costs	42	11	–	53
Production taxes	102	1	–	103
Depreciation, depletion and amortization of property and equipment	565	65	63	693
Amortization of goodwill	41	–	–	41
General and administrative expenses	81	10	2	93
Expenses related to mergers	60	–	–	60
Interest expense	144	10	1	155
Effects of changes in foreign currency exchange rates	–	3	–	3
Total costs and expenses	1,354	152	136	1,642
Earnings before income tax expense	872	156	114	1,142
INCOME TAX EXPENSE				
Current	113	2	16	131
Deferred	185	67	29	281
Total income tax expense	298	69	45	412
Net earnings	$ 574	87	69	730
Capital expenditures	$ 893	203	184	1,280

17. SEGMENT INFORMATION (CONTINUED)

	U.S.	CANADA	INTERNATIONAL	TOTAL
		(IN MILLIONS)		
AS OF DECEMBER 31, 1999:				
Current assets	$ 391	69	130	590
Property and equipment, net of accumulated depreciation, depletion and amortization	3,425	468	531	4,424
Other assets	944	–	138	1,082
Total assets	$ 4,760	537	799	6,096
Current liabilities	357	45	65	467
Long-term debt	2,077	339	–	2,416
Deferred tax liabilities (assets)	340	2	(18)	324
Other liabilities	318	3	47	368
Stockholders' equity	1,668	148	705	2,521
Total liabilities and stockholders' equity	$ 4,760	537	799	6,096
YEAR ENDED DECEMBER 31, 1999:				
REVENUES				
Oil sales	$ 332	80	149	561
Gas sales	502	114	12	628
Natural gas liquids sales	58	10	–	68
Other	15	5	1	21
Total revenues	907	209	162	1,278
COSTS AND EXPENSES				
Lease operating expenses	189	50	60	299
Transportation costs	22	12	–	34
Production taxes	43	1	1	45
Depreciation, depletion and amortization of property and equipment	309	65	32	406
Amortization of goodwill	16	–	–	16
General and administrative expenses	69	12	–	81
Expenses related to mergers	17	–	–	17
Interest expense	84	24	1	109
Effects of changes in foreign currency exchange rates	–	(13)	–	(13)
Distributions on preferred securities of subsidiary trust	7	–	–	7
Reduction of carrying value of oil and gas properties	464	–	12	476
Total costs and expenses	1,220	151	106	1,477
Earnings (loss) before income tax expense (benefit) and extraordinary item	(313)	58	56	(199)
INCOME TAX EXPENSE (BENEFIT)				
Current	15	3	5	23
Deferred	(119)	27	20	(72)
Total income tax expense (benefit)	(104)	30	25	(49)
Net earnings (loss) before extraordinary item	(209)	28	31	(150)
Extraordinary loss	(4)	–	–	(4)
Net earnings (loss)	$ (213)	28	31	(154)
Capital expenditures	$ 686	92	105	883

18. SUPPLEMENTAL QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Following is a summary of the unaudited interim results of operations for the years ended December 31, 2001 and 2000.

		2001				
		FIRST QUARTER	SECOND QUARTER	THIRD QUARTER	FOURTH QUARTER	FULL YEAR
		(IN MILLIONS, EXCEPT PER SHARE AMOUNTS)				
Oil, gas and natural gas liquids sales	$	1,011	710	571	688	2,980
Total revenues	$	1,024	725	586	740	3,075
Net earnings (loss)	$	400	136	85	(518)	103
Net earnings (loss) per common share:						
Basic	$	3.08	1.03	0.65	(4.13)	0.73
Diluted	$	2.96	1.01	0.64	(4.13)	0.72

		2000				
		FIRST QUARTER	SECOND QUARTER	THIRD QUARTER	FOURTH QUARTER	FULL YEAR
		(IN MILLIONS, EXCEPT PER SHARE AMOUNTS)				
Oil, gas and natural gas liquids sales	$	548	636	695	839	2,718
Total revenues	$	560	649	725	850	2,784
Net earnings	$	105	153	165	307	730
Net earnings per common share:						
Basic	$	0.81	1.19	1.27	2.37	5.66
Diluted	$	0.80	1.17	1.22	2.27	5.50

The second, third and fourth quarters of 2001 include $77 million, $10 million and $916 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 $556 million, respectively. The per share effect of these quarterly reductions was $0.48, $0.05 and $4.42, respectively.

The third and fourth quarters of 2000 include $57 million and $3 million, respectively, of expenses incurred in connection with the Santa Fe Snyder merger. The after-tax effect of these expenses was $35 million and $2 million, respectively. The per share effect of these quarterly reductions was $0.28 and $0.01, respectively.

19. SUBSEQUENT EVENT AND PRO FORMA FINANCIAL INFORMATION (UNAUDITED)

Mitchell Energy & Development Corp. Merger

On January 24, 2002, Devon completed its acquisition of Mitchell. Devon acquired Mitchell for the significant development and exploitation projects in each of Mitchell’s core areas, increased gas services operations and increased exposure to the North American natural gas market. Assuming the Mitchell merger had closed on December 31, 2001, the calculation of the purchase price and the preliminary allocation to assets and liabilities are shown below.

	(IN MILLIONS, EXCEPT SHARE PRICE)
Calculation and preliminary 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	$ 1,507
Cash paid to Mitchell stockholders, calculated at $31 per outstanding common share of Mitchell	1,567
Fair value of Devon common stock and cash to be issued to Mitchell stockholders	3,074
Plus estimated acquisition costs incurred	90
Plus fair value of Mitchell employee stock options assumed by Devon	25
Total purchase price	3,189
Plus fair value of liabilities assumed by Devon:	
Current liabilities	305
Long-term debt	363
Other long-term liabilities	76
Deferred income taxes	802
Total purchase price plus liabilities assumed	$ 4,735
Fair value of assets acquired by Devon:	
Current assets	193
Proved oil and gas properties	1,456
Unproved oil and gas properties	696
Gas services facilities and equipment	840
Other property and equipment	3
Other assets	57
Goodwill (none deductible for income tax purposes)	1,490
Total fair value of assets acquired	$ 4,735

Pro Forma Information

Set forth in the following tables are certain unaudited pro forma financial information as of December 31, 2001, and for the years ended December 31, 2001 and 2000. The information as of December 31, 2001, assumes the Mitchell merger had closed on such date. The information for the years ended December 31, 2001 and 2000, has been prepared assuming the Anderson acquisition and the Mitchell merger were consummated on January 1, 2000. 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, 2000. 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:

- In 2000, Devon recognized $60 million of expenses related to its merger with Santa Fe Snyder Corporation. Devon accounted for the Santa Fe Snyder merger using the pooling-of-interests method of accounting and, therefore, the expenses incurred related to the merger were expensed. The after-tax effect of these expenses in 2000 was $37 million.

- In 2000, Mitchell realized income tax savings of $13 million related to prior years' Section 29 tax credits and $6 million related to the reversal of prior years' deferred income taxes.

- In 2000, Mitchell recognized a $5 million gain from the exchange of certain gas services assets. Also in 2000, Mitchell recognized an $11 million impairment expense related to other gas services assets. Net of tax, these two events reduced Mitchell's 2000 net earnings by $4 million.

- On May 17, 2000, Anderson acquired all the outstanding shares of Ulster Petroleums Ltd. The summary unaudited pro forma combined statements of operations do not include any results from Ulster's operations prior to May 17, 2000.

- 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.

- In 2001, Devon elected to discontinue operations in Malaysia, Qatar, Thailand and on certain properties in Brazil. Accordingly, in 2001, Devon recorded an $87 million charge associated with the impairment of those properties. The after-tax effect of this reduction was $69 million.

- In 2001, Devon reduced the carrying value of its oil and gas properties by $916 million due to the full cost ceiling limitations. The after-tax effect of this reduction was $556 million.

- Anderson had a compensation plan pursuant to which it periodically issued awards referred to as share appreciation rights under which employees could earn compensation based on increases in the market price of Anderson's stock. Anderson awarded these rights in lieu of stock option grants. Pro forma general and administrative expenses reported in the accompanying unaudited pro forma statements of operations for the years ended December 31, 2001 and 2000 include $6 million and $5 million, respectively, of expenses related to these plans. After taxes, these plans had the effect of decreasing unaudited pro forma net earnings in the 2001 and 2000 periods by $3 million and $3 million, respectively. Devon acquired all outstanding rights as part of the Anderson acquisition. Accordingly, these rights will not affect Devon's net earnings subsequent to the closing of the Anderson acquisition.

- Mitchell has incentive compensation plans pursuant to which it has periodically issued awards referred to as bonus units under which employees can earn compensation based on increases in the market price of Mitchell common stock. Mitchell generally awards these bonus units in lieu of stock option grants. Pro forma general and administrative expenses reported in the accompanying unaudited pro forma statements of operations for the year 2000 include $21 million of expense related to these plans. After taxes, these plans had the effect of decreasing unaudited pro forma net earnings in the 2000 period by $14 million. Devon will not issue such bonus units after the merger.

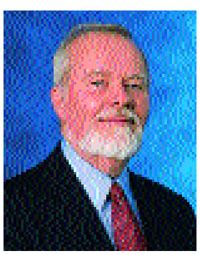
- Devon's historical results of operations for the years 2001 and 2000 include $34 million and $41 million, respectively, of amortization expense for goodwill related to previous mergers. As of January 1, 2002, in accordance with new accounting pronouncements recently issued, such goodwill will cease to be amortized and, instead, will be 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 and the Mitchell merger.

	PRO FORMA INFORMATION AS OF DECEMBER 31, 2001
	(DOLLARS IN MILLIONS)
Balance sheet data:	
Property and equipment, net	$ 11,872
Investment in common stock of ChevronTexaco Corporation	636
Goodwill	3,698
Total assets	17,784
Debentures exchangeable into shares of ChevronTexaco Corporation common stock	649
Other long-term debt	7,882
Stockholders' equity	4,694
Proved reserves:	
Oil (MMBbls)	602
Gas (Bcf)	7,186
NGLs (MMBbls)	211
MMBoe	2,011
Standardized measure of discounted future net cash flows	$ 6,185

	Pro Forma Information Year Ended December 31, 2001	2000
	(In millions, except per share amounts and production volumes)	
REVENUES		
Oil sales	$ 1,232	1,384
Gas sales	3,145	2,522
Natural gas liquids sales	308	342
Gas services revenue	1,169	1,202
Other	92	47
Total revenues	5,946	5,497
COSTS AND EXPENSES		
Lease operating expenses	769	640
Transportation costs	155	119
Production taxes	149	129
Gas services costs and expenses	1,038	984
Depreciation, depletion and amortization of property and equipment	1,393	1,192
Amortization of goodwill	34	41
General and administrative expenses	202	205
Expenses related to mergers	1	60
Interest expense	508	495
Effects of changes in foreign currency exchange rates	21	3
Change in fair value of financial instruments	16	–
Reduction of carrying value of oil and gas properties	1,155	–
Total costs and expenses	5,441	3,868
Earnings before income tax expense and cumulative effect of change in accounting principle	505	1,629
INCOME TAX EXPENSE		
Current	108	173
Deferred	68	412
Total income tax expense	176	585
Earnings before cumulative effect of change in accounting principle	329	1,044
Cumulative effect of change in accounting principle	49	–
Net earnings	378	1,044
Preferred stock dividends	10	10
Net earnings applicable to common stockholders	$ 368	1,034
Net earnings before cumulative effect of change in accounting principle per average common share outstanding:		
Basic	$ 2.03	6.62
Diluted	$ 2.00	6.45
Net earnings per average common share outstanding:		
Basic	$ 2.35	6.62
Diluted	$ 2.30	6.45
Weighted average common shares outstanding - basic	157	156
Weighted average common shares outstanding - diluted	164	161
Production volumes:		
Oil (MMBbls)	58	54
Gas (Bcf)	810	708
NGLs (MMBbls)	17	16
MMBoe	210	188

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.

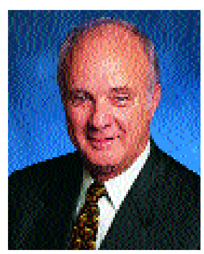
J. Larry Nichols, 59, a co-founder of Devon, was named Chairman of the Board of Directors in 2000. He has been a Director since 1971, President since 1976 and Chief Executive Officer since 1980. Nichols is a Director of the Domestic Petroleum Council, National Association of Manufacturers, Independent Petroleum Association of America, Natural Gas Supply Association, Independent Petroleum Association of New Mexico, Oklahoma Independent Petroleum Association and the National Petroleum Council. He serves on the Board of Governors of the American Stock Exchange. Nichols also serves on the boards of BOK Financial Corporation, Smedvig asa and Baker Hughes Incorporated. He has a degree in geology from Princeton University and a law degree from the University of Michigan.



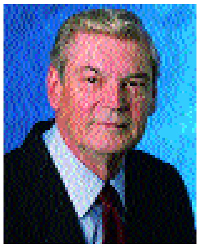
Thomas F. Ferguson, 65, has been a member of Devon's board since 1982 and is Chairman of the Audit Committee. He is the Managing Director of United Gulf Management Ltd., a wholly-owned subsidiary of Kuwait Investment Projects Company KSC. Ferguson represents Kuwait Investment Projects Company on the 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, 67, has been a Director of Devon since 1979 and serves as the Chairman of the Compensation and Stock Option Committee. He has been a Director of United American Energy Corp., an independent power producer, since 1992, and MetBank Holding Corporation since 1998. From 1978 to 1988, Gavrin served as a General Partner of Windcrest Partners. He previously was an officer of Drexel Burnham Lambert Incorporated.

Michael E. Gellert, 70, has been a board member since 1971 and serves as Chairman of the Nominating Committee. Gellert is a General Partner of Windcrest Partners, a private investment partnership in New York City, having held that position since 1967. From 1958 until his retirement in 1989, Gellert served in executive capacities with Drexel Burnham Lambert Incorporated and its predecessors in New York City. In addition to serving as a Director of Devon, Gellert also serves on the boards of High Speed Access Corporation, Humana Inc., Seacor Smit Inc., Six Flags Inc., Travelers Series Fund, Inc., Dalet Technologies and Smith Barney World Funds. He is also a member of the Putnam Trust Company Advisory Board to the Bank of New York.



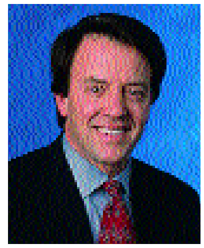
John A. Hill, 60, was elected to the Board of Directors in 2000. Prior to that, he served as a Director of Santa Fe Snyder Corporation. Hill has been with First Reserve Corporation, an oil and gas investment management company, since 1983 and currently serves as the Vice Chairman and Managing Director. Prior to joining First Reserve, he was President, Chief Executive Officer and Director of Marsh & McLennan Asset Management Company 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, a Director of TransMontaigne Inc., and various companies controlled by First Reserve Corporation and Continuum Health Partners.



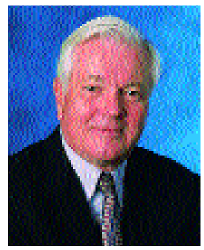
William J. Johnson, 67, was elected to the Board of Directors in 1999. Johnson has been a private consultant for the oil and gas industry for the past five years. He is President and a Director of JonLoc Inc., an oil and gas company, which he and his family are sole shareholders. Johnson has served as a Director of Tesoro Petroleum Corp. since 1996. From 1991 to 1994, Johnson was President, Chief Operating Officer and a Director of Apache Corporation.

Michael M. Kanovsky, 53, was elected to the Board of Directors in 1998. Kanovsky was a co-founder of Northstar Energy Corporation, acquired by Devon in 1998, and served on its Board of Directors since 1982. Kanovsky is President of Sky Energy Corporation, 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 Corporation.

J. Todd Mitchell, 43, was elected to the Board of Directors in January 2002. He previously was a member of the Board of Directors of Mitchell Energy & Development Corp. from 1993 to 2002. Mitchell has served as President of GPM, Inc., a family-owned investment company, since 1998 and as President and Geologist to Dolomite Resources, Inc., a privately owned mineral exploration and investments company, since 1987. He has been Chairman of Rock Solid Images, a privately owned seismic data analysis software company, since 1998.

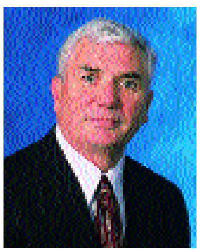


Robert A. Mosbacher, Jr., 50, was elected to the Board of Directors in 1999. Since 1986, he has served as President and Chief Executive Officer of Mosbacher Energy Company and, since 1995, as Vice Chairman of Mosbacher Power Group. Mosbacher was previously a Director of PennzEnergy Company and served on the Executive Committee. He currently serves as a Director of JPMorgan Chase and Company and is on the Executive Committee of the U.S. Oil & Gas Association.

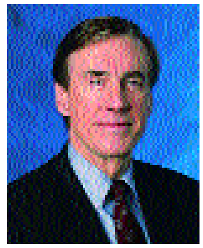


Robert B. Weaver, 63, was elected to the Board of Directors in 1999. He served as an Energy Finance Specialist at Chase Manhattan Bank, N.A., where he was in charge of its worldwide energy group from 1981 until his retirement in 1994. Weaver was previously a Director of PennzEnergy Company beginning in 1998, where he served as Chairman of the Audit Committee and was a member of the Compensation Committee.

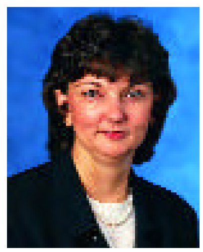
Brian J. Jennings, 41, was elected Senior Vice President – Corporate Development in 2001. He joined Devon in 2000 as Vice President – Corporate Finance. Prior to joining Devon, Jennings was a Managing Director in the Energy Investment Banking Group of PaineWebber, Inc. He began his banking career at Kidder, Peabody in 1989, before moving to Lehman Brothers in 1992, and later to PaineWebber in 1995. Jennings specialized in providing strategic advisory and corporate finance services to public and private companies in the E&P and oilfield service sectors. He began his energy career with ARCO International Oil & Gas, a subsidiary of Atlantic Richfield Company. Jennings received his bachelor's of science degree in petroleum engineering from the University of Texas at Austin and his master's of business administration from the University of Chicago's Graduate School of Business.



J. Michael Lacey, 56, was elected Senior Vice President – Exploration and Production in 1999. Lacey had previously joined Devon as Vice President of Operations and Exploration in 1989. Prior to his employment with Devon, Lacey served as General Manager in Tenneco Oil Company'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 both undergraduate and graduate degrees in petroleum engineering from the Colorado School of Mines.



Duke R. Ligon, 60, was elected Senior Vice President – General Counsel in 1999. He had previously joined Devon as Vice President – General Counsel in 1997. In addition to Ligon's primary role of managing the company's corporate legal matters (including litigation), he has direct involvement with governmental affairs, purchasing and Devon's merger and acquisition activities. Prior to joining Devon, Ligon practiced energy law for 12 years, most recently as a partner at the law firm of Mayer, Brown & Platt in New York City. In addition, he was a Senior Vice President and Managing Director for investment banking at Bankers Trust Company in New York City for 10 years. Ligon also served for three years in various positions with the U. S. Departments of the Interior and Treasury, as well as the Department of Energy. He holds an undergraduate degree in chemistry from Westminister College and a law degree from the University of Texas School of Law.

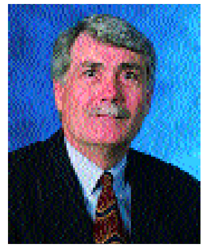


Marian J. Moon, 51, was elected Senior Vice President – Administration in 1999. She is responsible for Human Resources, Office Administration, Information Technology, Process Development and Corporate Governance. Moon has been with Devon for 17 years, serving in various capacities, including Manager of Corporate Finance. Prior to joining Devon, she was employed by Amarex, Inc., for 11 years, where she served most recently as Treasurer. Moon is a member of the American Society of Corporate Secretaries. She is a graduate of Valparaiso University.

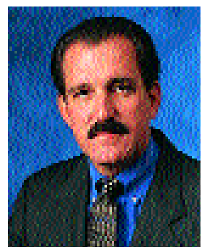
John Richels, 50, was elected Senior Vice President – Canadian Division in 2001. Richels was previously Chief Executive Officer of Northstar Energy Corporation, acquired by Devon in 1998. He served as Northstar's Executive Vice President and Chief Financial Officer from 1996 to 1998 and was on the Board of Directors from 1993 to 1996. Prior to joining Northstar, Richels was Managing Partner, Chief Operating Partner and a member of the Executive Committee of the Canadian–based national law firm, Bennett Jones. He also served, on a secondment from Bennett Jones, as General Counsel of the XV Olympic Winter Games Organizing Committee in Calgary, Alberta. Richels previously served as a Director of a number of publicly traded companies and is a member of the Board of Governors of the Canadian Association of Petroleum Producers and the Mount Royal College Foundation. He holds a bachelor's degree in economics from York University and a law degree from the University of Windsor.

Darryl G. Smette, 54, was elected Senior Vice President – Marketing in 1999. Smette previously held the position of Vice President – Marketing and Administrative Planning since 1989. He joined Devon in 1986 as Manager of Gas Marketing. Smette's marketing background includes 15 years with Energy Reserves Group, Inc./BHP Petroleum (Americas), Inc., most recently as Director of Marketing. He is also an oil and gas industry instructor, approved by the University of Texas Department of Continuing Education. Smette is a member of the Oklahoma Independent Producers Association, Natural Gas Association of Oklahoma and the American Gas Association. He holds an undergraduate degree from Minot State College and a master's degree from Wichita State University.

William T. Vaughn, 55, was elected Senior Vice President – Finance in 1999. He previously served as Vice President of Finance in charge of commercial banking functions, accounting, tax and information services since 1987. Prior to that, he was Controller from 1983 to 1987. Vaughn's previous experience includes serving as Controller of Marion Corporation for two years and employment with Arthur Young & Co. for seven years, most recently as Audit Manager. He is a Certified Public Accountant and a member of the American Institute of Certified Public Accountants. Vaughn graduated from the University of Arkansas with a bachelor's of science degree.



Rick D. Clark, 54, was elected Vice President and General Manager – Permian/Mid–Continent Division in 1999. He previously served as Production/Operations Manager since joining Devon in 1995, where he was responsible for the company's drilling and production activities. Prior to joining Devon, Clark was employed by Patrick Petroleum Company where he served as Executive Vice President, Operations and Corporate Development since 1988. Prior to that, Clark worked in various production engineering, reservoir engineering, financial and managerial capacities for Ladd Petroleum Corporation and Conoco Inc. He is a member of the Society of Petroleum Engineers. Clark holds a degree in petroleum engineering from the Colorado School of Mines.



Don D. DeCarlo, 45, was elected Vice President and General Manager – Rocky Mountain Division in 2000. He previously served as Vice President and General Manager, Rocky Mountain Division, for Santa Fe Snyder Corporation. DeCarlo began his professional career in 1978 with Tenneco Oil Company in Oklahoma City. In 1989 he joined Santa Fe Energy Resources as an Engineering Manager in Tulsa, Oklahoma. During his 11–year tenure with Santa Fe, DeCarlo held management positions of increasing responsibilities in Bakersfield, California, Midland, Texas and most recently in Denver. He received a bachelor's of science degree in petroleum engineering from West Virginia University. DeCarlo is a member of the Society of Petroleum Engineers and currently holds the position of Vice President for the Independent Petroleum Association of the Mountain States.

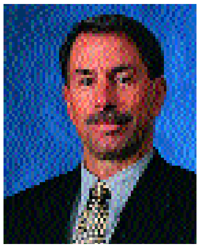
Janice A. Dobbs, 53, was elected Corporate Secretary in 2001. She joined Devon in 1999 as Manager of Corporate Governance and Assistant Corporate Secretary. From 1993 to 1999, Dobbs served as the Corporate Secretary and Compliance Manager of Chesapeake Energy Corporation. From 1975 until her association with Chesapeake, Dobbs was the Corporate/ Securities Legal Assistant with the law firm of Andrews Davis Legg Bixler Milsten & Price, Inc. in Oklahoma City. Prior to that, she was the Corporate/Securities Legal Assistant with Texas International Petroleum Company. Dobbs is a Certified Legal Assistant, an associate member of the American Bar Association and a member of the American Society of Corporate Secretaries.

Danny J. Heatly, 46, was elected Vice President – Accounting in 1999. He had previously served as Controller since 1989. Prior to joining Devon, Heatly was associated with Peat Marwick Main & Co. (now KPMG LLP) in Oklahoma City for 10 years with various duties, including Senior Audit Manager. He is a Certified Public Accountant and a member of the American Institute of Certified Public Accountants and the Oklahoma Society of Certified Public Accountants. Heatly graduated with a bachelor's of accountancy degree from the University of Oklahoma.

Richard E. Manner, 55, was elected Vice President – Information Services in 2000. Manner has been an Information Technology professional for 25 years. Prior to joining Devon, he was employed by Unisys in Houston. There he served for 14 years in various positions, including Director of Information Systems. Prior to his tenure with Unisys, Manner spent two years with a National Aeronautics and Space Administration contractor as a software engineer, and eight years with AMF Tuboscope where he supervised the design of oilfield inspection instrumentation and facilities. He is a registered professional engineer and a member of the Society of Professional Engineers. Manner received an electrical engineering degree from the University of Oklahoma.

R. Alan Marcum, 35, was elected Controller in 1999. Marcum has been with Devon since 1995, most recently as Assistant Controller. He is responsible for international and operations accounting for Devon. Prior to joining Devon, Marcum was employed by KPMG Peat Marwick (now KPMG LLP) as a Senior Auditor, with responsibilities including special engagements involving due diligence work, agreed upon procedures and SEC filings. He holds a bachelor's of science degree from East Central University, where he majored in accounting and finance. Marcum is a Certified Public Accountant and a member of the Oklahoma State Society of Certified Public Accountants.

Gary L. McGee, 52, was elected Vice President – Government Relations in 1999. He had previously served as Devon's Treasurer and Controller. Prior to joining Devon, McGee served as Vice President of Finance with KSA Industries, Inc., a private holding company with various interests, including oil and gas exploration. McGee also held various accounting positions with Adams Resources and Energy Company and Mesa Petroleum Company. McGee is a member of the Petroleum Association of Wyoming and the New Mexico Oil & Gas Association. He is a graduate of the University of Oklahoma, where he received a degree in accounting.



Paul R. Poley, 48, was elected Vice President – Human Resources in 2000. Poley was previously employed by Fleming Companies in Oklahoma City, most recently as Director of Human Resources Planning and Development. At Fleming, his responsibilities included human resources development, management succession, strategic planning, performance management and training for 39,000 employees. Prior to his 11 years at Fleming, Poley was Regional Personnel Manager for International Mill Service, Inc. He is a member of the board of the Southwest Benefits Association. Poley received his bachelor's of arts degree in sociology from Bucknell University.

Terrence L. Ruder, 49, was elected Vice President and General Manager – Marketing and Midstream Division in 2001. Ruder has been with Devon since 1999, most recently as President of Thunder Creek Gas Services, a gas pipeline subsidiary located in Wyoming. He has more than 25 years of energy industry experience in both domestic and international capacities. Prior to joining Devon, Ruder held a variety of marketing and business development positions with BHP Petroleum and BHP Power, most recently as Senior Vice President and General Manager of BHP Power in Brazil. He graduated with a bachelor's of business administration degree in finance from Wichita State University.

David J. Sambrooks, 43, was elected Vice President and General Manager – International Division in 2001. He previously served as Production Manager, South America. Prior to the merger with Devon, he served as General Manager of International Business Development and Western Hemisphere Production for Santa Fe Snyder Corporation. Sambrooks began his professional career in 1980 with Sun Exploration and Production Company (later Oryx Energy) and held positions of increasing responsibility in Houston, Corpus Christi, Texas and Midland, Texas before joining Santa Fe Energy Resources in 1990. During his 10–year tenure with Santa Fe, Sambrooks held progressive positions in engineering and management covering south Texas, offshore Gulf of Mexico, and beginning in 1993, international. He received a bachelor's of science degree in mechanical engineering from the University of Texas at Austin and a master's of business administration from the University of Houston.

William A. Van Wie, 56, was elected to Vice President and General Manager – Gulf Division in 1999. Van Wie previously served as Senior Vice President and General Manager – Offshore for PennzEnergy. He began his career as a Geologist for Tenneco Oil Company's Frontier Projects Group in 1974. Following the sale of Tenneco's Gulf of Mexico properties to Chevron in 1988, he joined that company as Division Geologist. In 1992, he moved to Pennzoil Exploration and Production Company as Vice President/Exploitation Manager. He then served as Manager of Offshore Exploration for Amerada Hess Corporation, before rejoining Pennzoil in 1997. He is an active member of the American Association of Petroleum Geologists, serves as a Trustee for the American Geological Institute Foundation, is a Vice Chairman of Independent Petroleum Association of America's Offshore Committee and is also a member of the National Ocean Industries Association. Van Wie received his bachelor's of science degree in geology from St. Lawrence University in Canton, New York and a master's degree and Ph.D. in geology from the University of Cincinnati.

Vincent W. White, 44, was elected Vice President – Communications and Investor Relations in 1999. He has primary responsibility for Devon's investor communications, media relations and employee communications. White previously served as Director of Investor Relations since 1993. Prior to joining Devon, he served as Controller of Arch Petroleum Inc. and was an auditor with KPMG Peat Marwick (now KPMG LLP). White is a Certified Public Accountant and a member of the Petroleum Investor Relations Association, the National Investor Relations Institute and the American Institute of Certified Public Accountants. He received his bachelor of accounting degree from the University of Texas at Arlington.

Dale T. Wilson, 42, was elected Treasurer of Devon in 1999. He has primary responsibility for the company's treasury and risk management functions. Prior to joining Devon, Wilson was employed in the banking industry for 17 years, including Bank of America for 15 years as a Managing Director of the Energy Finance Group. He has been active in oil and gas trade associations and is currently a member of the Association for Financial Professionals. Wilson graduated from Baylor University with a bachelor's degree in finance and accounting.

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.

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.

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. NGLs 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.

Prospect: An area designated for the potential drilling of development or exploratory wells.

Proved reserves: Estimates of oil, gas, and natural gas liquids 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%.

Section 29 tax credit: A tax credit prescribed by Section 29 of the Internal Revenue Code. The credit is available for certain types of gas production from a non-conventional source, such as coal deposits.

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. 2D seismic provides two-dimensional information while 3D creates three-dimensional pictures. 4C, or four-component, seismic is a developing technology that utilizes measurement and interpretation of shear wave data. 4C 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

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

BOD: Barrels of oil 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. Natural gas liquids 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

Investor Information

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Oklahoma City, OK 73102-8260

Gulf Division
Devon Energy Corporation
Devon Energy Tower
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Houston, TX 77002

International Division
Devon Energy Corporation
840 Gessner, Suite 1100
Houston, TX 77024

Canadian Division
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
EquiServe
Client Administration
150 Royall Street
Clinton, MA 02021
Toll Free: (800) 733-5001
http://www.equiserve.com

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

Investor Relations Contacts

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Individuals and Brokers:
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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 stockholders' meeting will be held at 10:00 a.m. central time on Thursday, May 16, 2002, in the Egbert Room at the Renaissance Hotel, 10 North Broadway, Oklahoma City, Oklahoma.

Independent Auditors
KPMG LLP
Oklahoma City, Oklahoma

Stock Trading Data
Devon Energy Corporation's common stock is traded on the American Stock Exchange (symbol: DVN). There are approximately 31,000 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:
http://www.devonenergy.com
Devon's website contains press releases, SEC filings, answers to commonly asked questions, stock quote information and more.

Common Stock Trading Data

Quarter	High	Low	Last	Volume
2000				
First	$ 48.56	31.38	48.56	23,705,600
Second	$ 60.94	43.75	56.19	38,676,300
Third	$ 62.56	42.56	60.15	62,874,500
Fourth	$ 64.74	48.00	60.97	52,239,500
2001				
First	**$ 65.75**	**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**

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www.devonenergy.com