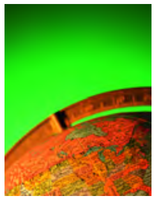
devon

The Right Resources.

DEVON ENERGYCORPORATION
2000 ANNUAL REPORT

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.



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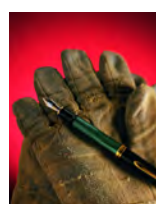


Devon Energy Corporation is engaged in oil and gas exploration, production and property acquisitions. Devon ranks among the top five U.S.-based independent oil and gas producers and is included in the S&P 500 Index. Approximately 75 percent of the company's proved reserves are located in North America. Devon also has significant international operations in Azerbaijan, Southeast Asia, South America and West Africa. Devon's common shares trade on the American Stock Exchange under the 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,*
- *Optimizing production operations to control costs, and*
- *Maintaining a strong balance sheet with limited debt.*

FIVE-YEAR HIGHLIGHTS

The information presented below does not reflect Devon's historical reported results. It has been restated to reflect the combined results of Devon and Santa Fe Snyder for all periods presented. This presentation conforms with the accounting method used for the August 2000 merger, the pooling-of-interests method. The restated data varies significantly from that reported for Devon on a stand-alone basis. For example, Devon previously reported total revenues and net earnings of $734 million and $95 million, respectively, for the year ended December 31, 1999. As restated below, the combined company had total revenues of $1,277 million and a net loss of $154 million for the year ended December 31, 1999.

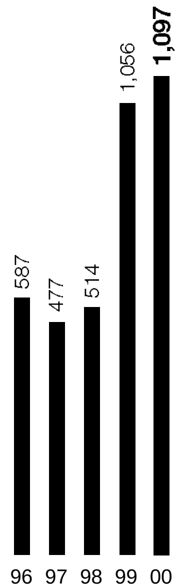
YEAR ENDED DECEMBER 31,		1996	1997	1998	1999	2000	LAST YEAR CHANGE
FINANCIAL DATA (1) (Thousands, except per share data)							
Total Revenues	$	870,257	1,014,523	706,226	1,277,468	2,784,103	118%
Cash Expenses (2)	$	427,796	457,631	382,757	614,470	1,035,836	69%
Cash Margin	$	442,461	556,892	323,469	662,998	1,748,267	164%
Non-cash Expenses							
Foreign Exchange Rate Changes on Long-term Debt	$	199	5,860	16,104	(13,154)	2,408	NM
Reduction of Carrying Value of Oil & Gas Properties	$	33,100	641,314	422,500	476,100	—	(100%)
Other Non-cash Expenses (including deferred taxes)	$	258,159	127,909	120,750	354,196	1,015,517	187%
Net Earnings (Loss)	$	151,003	(218,191)	(235,885)	(154,144)	730,342	NM
Net Earnings (Loss) Applicable to Common Shareholders	$	103,803	(230,191)	(235,885)	(157,795)	720,607	NM
Net Earnings (Loss) per Share							
Basic	$	1.97	(3.35)	(3.32)	(1.68)	5.66	NM
Diluted	$	1.92	(3.35)	(3.32)	(1.68)	5.50	NM
Weighted Average Common Shares Outstanding							
Basic		52,744	68,732	70,948	93,653	127,421	36%
Diluted		55,553	75,366	76,932	99,313	131,730	33%
Cash Dividends per Common Share (3)	$	0.09	0.09	0.10	0.14	0.17	21%

DECEMBER 31,		1996	1997	1998	1999	2000	LAST YEAR CHANGE
Total Assets	$	2,241,890	1,965,386	1,930,537	6,096,360	6,860,478	13%
Debentures Exchangeable into Shares of Chevron Corporation Common Stock (4)	$	—	—	—	760,313	760,313	—
Other Long-term Debt	$	361,500	427,037	735,871	1,656,208	1,288,523	(22%)
Convertible Preferred Securities of Subsidiary Trust (5)	$	149,500	149,500	149,500	—	—	—
Stockholders' Equity	$	1,159,772	1,006,546	749,763	2,521,320	3,277,604	30%
Working Capital	$	80,036	55,743	6,792	122,950	305,150	148%
PROPERTY DATA (1)							
Proved Reserves (net of royalties)							
Oil (MBbls)		375,355	218,741	235,457	496,717	459,244	(8%)
Gas (MMcf)		1,157,719	1,403,204	1,476,994	2,949,627	3,458,184	17%
Natural Gas Liquids (MBbls)		18,490	24,478	32,679	67,817	61,757	(9%)
Total (MBoe) (6)		586,798	477,086	514,302	1,056,139	1,097,366	4%
SEC 10% Present Value (7) (Thousands)	$	4,095,248	2,100,344	1,527,539	5,811,723	17,737,043	205%

YEAR ENDED DECEMBER 31,	1996	1997	1998	1999	2000	LAST YEAR CHANGE
Production (net of royalties)						
Oil (MBbls)	33,180	32,565	25,628	31,756	42,561	34%
Gas (MMcf)	123,286	186,239	198,051	304,203	426,146	40%
Natural Gas Liquids (MBbls)	2,055	2,842	3,054	5,111	7,400	45%
Total (MBoe) (6)	55,783	66,447	61,691	87,568	120,985	38%

(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 1999 include only eight months activity attributable to the Snyder Oil transaction and four and one-half months activity attributable to the PennzEnergy transaction.
(2) Includes 2000 merger costs of $60.4 million, 1999 merger costs of $16.8 million, and 1998 merger costs of $13.1 million.
(3) The cash dividends per share presented are not representative of the actual amounts paid by Devon on an historical basis. For the years 2000, 1999, 1998, 1997 and 1996, Devon's historical cash dividends per share were $0.20, $0.20, $0.20, $0.20 and $0.14, respectively.
(4) Debentures exchangeable into 7.1 million shares of Chevron common stock beneficially owned by Devon.
(5) Reflects the issuance of 2.99 million shares of preferred securities on July 10, 1996. These shares were redeemed and converted to 4.9 million Devon common shares on November 30, 1999.
(6) Gas converted to oil at the ratio of 6 Mcf:1 Bbl.
(7) Before income taxes.
NM Not a meaningful figure.

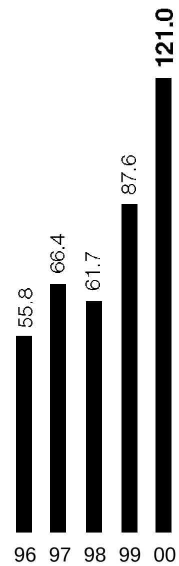
PROVED OILAND GAS RESERVES
(net of royalties) (MMBoe*)



** Gas converted to oil equivalent at the ratio of 6 Mcf:1 Bbl.*

Year-end reserves reached a record 1.1 billion barrels.

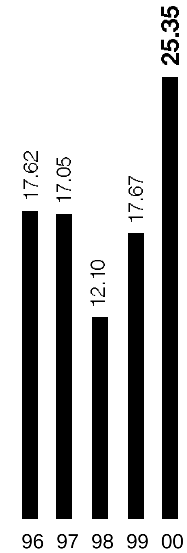
OILAND GAS PRODUCTION
(net of royalties) (MMBoe*)



** Gas converted to oil equivalent at the ratio of 6 Mcf:1 Bbl.*

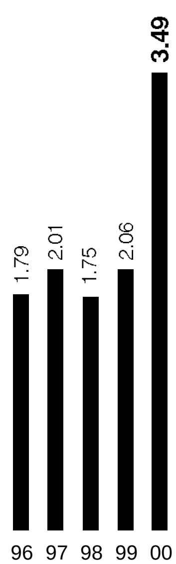
A 38% increase in oil and gas production coupled with...

AVERAGE OILPRICE RECEIVED BYDEVON ($ per Bbl)



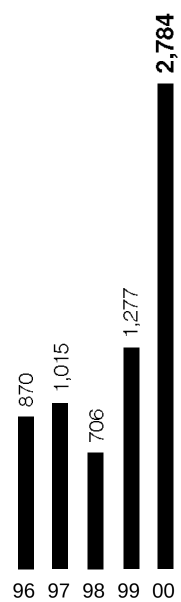
...higher realized oil prices...

AVERAGE GAS PRICE RECEIVED BYDEVON ($ per Mcf)



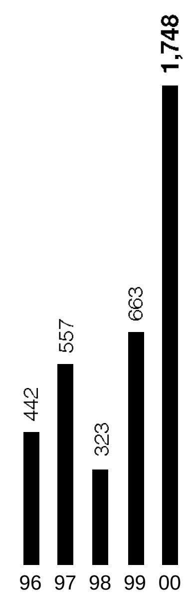
...and higher realized natural gas prices...

TOTAL REVENUES
($ Millions)



...more than doubled total revenues...

CASH MARGIN*
($ Millions)



** Revenues less cash expenses.*

...yielding a cash margin exceeding the previous three years combined.

The right direction.

In 2000, Devon Energy Corporation extended its chronicle of record-breaking performances:

- **Net earnings climbed to $730 million, or $5.50 per share, an all-time record.**
- **Revenues were $2.8 billion, up 118% over our previous all-time record set in 1999.**
- **Oil and natural gas production reached an all-time high of 121 million barrels of oil equivalent, 38% greater than 1999.**
- **Estimated proved reserves of oil and natural gas also advanced to record levels—1.1 billion barrels of oil equivalent.**
- **1,261 successful oil and gas wells were drilled replacing 129% of 2000 production.**

These results reflect the impact of one of Devon's most important achievements of the year—our merger with Santa Fe Snyder Corporation. The merger was announced in May and was overwhelmingly approved by the shareholders of both companies on August 29, 2000. We issued 40.6 million new Devon common shares in exchange for all the outstanding shares of Santa Fe. This merger brought to Devon 386 million equivalent barrels of oil and gas reserves, substantial current production and 16 million undeveloped acres of land. More importantly, it was additive to oil and gas reserves per share, production per share, earnings per share and cash flow per share.

THE RIGHT ASSETS

In addition to improving company-wide and per share operating results, the Santa Fe merger strengthens our portfolio of oil and gas properties. The merger adds significantly to each of Devon's historic core operating areas in the U.S. In the Permian Basin of west Texas and southeast New Mexico, Devon was already a top operator—the merger further reinforces our dominance. We now control almost 800,000 net acres in the Permian and we are the largest independent oil producer in the state of New Mexico. In the Rocky Mountains, Santa Fe's portfolio of high-quality conventional oil and gas properties complements Devon's dominant coalbed methane position. In the Gulf of Mexico, Santa Fe's offshore blocks further reinforce our position as one of the largest operators on the shelf. In addition, Santa Fe brings an inventory of deepwater Gulf development projects with a growing production profile. Outside North America, the Santa Fe merger expands and diversifies our international operations. Santa Fe's producing properties, most notably in South America and Indonesia, and its exploration prospects in West Africa, are strategic additions to Devon's world-class oil field in Azerbaijan.

Building the right assets not only requires assembling concentrations of high-quality oil and gas properties, it requires divesting those properties that do not fit. To that end, we sold several non-core properties during 2000. Our divestitures included the SACROC oil field in the Permian Basin, all of our oil and gas properties in Appalachia and our holdings in Venezuela. These were assets that came to Devon in the 1999 acquisition of PennzEnergy. We sold these properties because they had low operating margins or were outside our areas of geographic focus.

Our 2001 exploration and development budget of $1.1 billion should yield yet another record for annual oil and gas production this year. This near-term growth will result primarily from lower-risk drilling projects in our traditional operating areas in North America. However, Devon's expansion in recent years has transformed the company into a formidable competitor for industry opportunities around the globe. In addition to near-term production growth, our 2001 budget will fund a record $390 million of high potential exploration projects. These projects range from deep gas exploration in the foothills of British Columbia to testing world-class oil prospects in the deepwater Gulf of Mexico. These projects have the potential to provide Devon and its shareholders meaningful long-term growth.

THE RIGHT ORGANIZATION

Not only have Devon's mergers and acquisitions brought the company concentrations of high quality oil and gas properties, they have brought together a wealth of human resources as well. Devon's employees, old and new, have joined together to meet the challenges of managing the company's growth.

Devon's dramatic growth over the last few years has demanded changes to the company's organizational structure. We have organized Devon's U.S. properties into three operating divisions. We integrated Santa Fe's Gulf of Mexico assets into Devon's Gulf Division under the leadership of that division's Vice President and General Manager, Bill Van Wie. Rick Clark, a Devon Vice President and General Manager prior to the merger, assumed responsibility for the combined company's Permian/Mid-Continent Division. Following the merger, Don DeCarlo joined Devon from Santa Fe as Vice President and General Manager of the newly created Rocky Mountain Division. Duane Radtke also joined us from Santa Fe to direct our expanding International Division. Our Canadian Division remains under the capable leadership of John Richels.

Bill Van Wie, Don DeCarlo and Duane Radtke are but three of the many talented and experienced professionals that have joined Devon over the last two years. By selectively offering positions to members of the PennzEnergy and Santa Fe staffs, we have assembled a highly qualified and energized team. Our staff of petrotechnical professionals has grown to over 350 from about 100 just two years ago.

Terms of the merger also predicated changes to Devon's Board of Directors. William Greehey, John Hill and Melvyn Klein joined the board from Santa Fe. At that transition Moulton Goodrum, John Hagg, Henry Hamman, H. R. Sanders and Brent Scowcroft left the Devon board. I acknowledge the valuable contribution of each departing director and heartily welcome our new directors. James Pate, who resigned his position as Chairman of the Board in 2000, warrants special recognition. The acquisition and smooth integration of PennzEnergy would not have been possible without his valuable assistance.

James Payne, previously CEO and Chairman of Santa Fe Snyder, joined Devon as Vice Chairman of the Board upon completion of the merger. Jim retired in January of 2001. His support and guidance during the merger and integration of our companies were invaluable. We are deeply indebted to him for this lasting contribution.

Just six months after the Santa Fe merger, integration of the two companies is essentially complete. This process was expedited by the natural geographic fit of the Devon and Santa Fe properties. Contributing to the ease of integration was the valuable experience gained through our successful integration of PennzEnergy in 1999. The structural reorganization Devon implemented with the PennzEnergy acquisition provided a ready platform for further growth. When the opportunity to merge with Santa Fe arose, Devon was positioned to confidently take another leap forward.

THE RIGHT BALANCE

In spite of the challenge of integrating the largest merger in the company's history during 2000, we demonstrated remarkably good performance with the drill bit. We successfully completed 95% of the 1,328 wells drilled during the year. This added oil and gas reserves through discoveries and revisions of 156 million barrels of oil equivalent. Before acquisitions, we replaced 129% of total 2000 production. With related capital costs of just over $900 million, our 2000 finding and development cost from drilling and revisions was only $5.80 per barrel of oil equivalent.

Projects spanning the risk spectrum contributed to the success of Devon's 2000 drilling efforts. We drilled over 500 successful low-risk wells in our coalbed methane projects in the Rocky Mountains. In the Permian/Mid-Continent Division we drilled 322 wells with a success rate of 98%. In the Gulf of Mexico we executed an active exploitation program with excellent results. These low risk exploitation and development projects were balanced with high impact exploratory drilling. We successfully completed high potential wells in the Gulf of Mexico, in the foothills of western Canada and in south Louisiana. For more detail on Devon's 2000 drilling activities, see the properties discussion beginning on page 15 of this annual report.

THE RIGHT FINANCIAL RESOURCES

During 2000, we took important steps to further strengthen our balance sheet and ensure a level of financial flexibility that will allow us to capture future growth opportunities:

- **In June 2000, we issued $346 million of zero coupon convertible debentures at an effective annual interest rate of just 3.875%. The proceeds from the sale of these debentures were used primarily to repay higher rate debt.**
- **In August 2000, we increased our unsecured long-term credit facilities to $1 billion.**
- **Also in August, we initiated a commercial paper program that allows Devon to meet short-term borrowing needs at rates available to only the largest and strongest of companies.**

Mergers and acquisitions, especially when debt is assumed, can weaken the financial strength of the acquirer. Quite the opposite was the case with Devon and Santa Fe. Immediately upon closing the merger in August, Devon received an upgrade to our already enviable credit rating. In doing so, the rating agencies applauded our larger property base, increased cash flow and financial discipline. Devon's credit rating now puts us in the fellowship of much larger companies.

THE RIGHT OUTLOOK

Devon's impressive financial results in 2000 reflect exceptionally high prices for oil and natural gas. The outlook for 2001 oil and gas prices remains unusually strong. However, we know from past experience that market conditions can change quickly. Armed with this knowledge, we will continue to position Devon to take advantage of volatile oil and gas prices. We will make investment decisions based on realistic long-term oil and gas price assumptions. We will concentrate our operations in the areas where we can be most competitive. We will keep our overall cost structure low and our balance sheet strong.

As I look to 2001 and beyond, I am extremely optimistic about Devon's future. Our base of high quality producing properties should generate another year of record oil and gas production. In addition, we have more long-term growth potential through exploration than ever before. We have dedicated and experienced staff across the organization. We have extensive experience in completing acquisitions that deliver per share growth. And we have the financial strength and flexibility to pursue almost any opportunity we select. Devon Energy Corporation has *the right resources* to deliver the growth that you have come to expect.

J. LARRY NICHOLS
President, Chief Executive Officer
and Chairman of the Board of Directors
March 12, 2001

Environmental and Safety Awards

Devon is routinely recognized by governments and industrial groups for exemplary environmental, health and safety performance. In 2000, Devon received four prestigious awards for environmental and safety excellence:

- Bureau of Land Management *Director's Excellence Award* for operations in New Mexico,
- The Gas Processors Association *Accident Prevention Award* for operations at our Worland, Wyoming gas plant,
- A *Gold Champion Level Reporter Award* from Canada's Climate Change Voluntary Challenge and Registry Incorporated, and
- Special recognition by the Republic of Indonesia for Devon's outstanding safety record as an operator on the island of Sumatra.

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

The right strategy.

At the time of the PennzEnergy acquisition in late 1999, it was the largest in your history. What is your appraisal of the PennzEnergy merger now that you have had another year to evaluate its results?

Larry Nichols, President, CEO and Chairman of the Board:

The PennzEnergy acquisition was an unqualified success and our timing could not have been better. The transaction doubled our oil and gas production just as prices began to increase significantly. It was highly accretive to asset value per share and to per share operating results. The merger broadened the scope of our operations domestically and provided a platform from which to expand internationally. It gave us added marketing clout and purchasing strength at a time when service and supply costs were starting to rise. By every measure, the PennzEnergy deal was a home run.

Two operating areas stand out as especially notable successes: the Gulf of Mexico and the Raton Basin. The offshore Gulf of Mexico was a core area for PennzEnergy. With our merger, Devon immediately reached critical mass in the Gulf. However, PennzEnergy had been suffering significant production declines in the Gulf. We knew from our pre-merger evaluation that PennzEnergy had high quality properties in the Gulf and solid technical expertise. We believed that with greater capital investment and encouragement from management, the Gulf Division could turn around the production decline. We were right. In 2000, we had a series of Gulf drilling successes and by the second quarter production was on the rise.

The Raton Basin is another success story. Devon is a leader in coalbed methane production and technology. Our fields in the San Juan Basin in New Mexico have produced for over a decade. In 1998, we expanded our coalbed methane expertise into the Powder River Basin of Wyoming. It is now the fastest growing gas producing area in the company. PennzEnergy brought us a third, major coalbed methane play. Through the merger we acquired 700,000 acres in the Vermejo Park Ranch in the Raton Basin in northeastern New Mexico. The ranch contained vast coal deposits prospective for coalbed methane development. In our evaluation of PennzEnergy, we learned that the area had interesting potential. However, because the acreage was unproven and had no production history, we were unwilling to attribute significant value when negotiating the purchase of PennzEnergy. Since that time, we have been aggressively developing this asset. We now have around 120 wells producing and expect to drill another 100 in each of the next few years. The results have been very encouraging. We have booked more than 140 billion cubic feet of proved reserves to date and production is climbing. It now appears that the PennzEnergy merger put a third jewel on our coalbed methane crown.

Early in 2001, Devon hedged the price on a significant portion of its expected 2002 natural gas production. Why?

Darryl Smette, Senior Vice President – Marketing:

Oil and gas prices are influenced by weather patterns, varying levels of economic activity, the availability of risk capital and a host of other variables beyond our control. Since we cannot reliably predict prices over any extended period, we accept this uncertainty as a given in our industry. Nevertheless, we believe that by limiting debt, controlling costs and deploying capital based on realistic price assumptions, we can achieve attractive operating margins—even when prices are low.

Early this year, in response to unusually high natural gas prices, we entered into a series of hedging transactions with some very large and well capitalized organizations. These transactions supplemented other fixed price sales contracts and financial hedges already in place. These new transactions allowed us to lock in fixed prices and ranges of prices for the second half of 2001 and for 2002. Swaps and costless collars were the vehicles utilized. The swaps captured a gas price that is more than double the average price we received over the last five years. The costless collars provide a floor that is at least 35% greater than the average price received during the last five years.

In exchange for low-end price protection, we gave up some possible price upside should actual prices exceed the swap price or the upper end of the collars. Because our underlying belief is that gas prices will tend to normalize over time, we were presented with an opportunity that limited the downside on a significant portion of our gas production. And by keeping over 50% of our expected production unhedged, we will continue to participate in any extended price rallies.

With record revenues, Devon is generating cash flow significantly in excess of capital requirements. What are your plans for use of the excess cash?

Allen Turner, Senior Vice President – Corporate Development:

In 2000, our cash margin (revenues less cash expenses) of $1.7 billion exceeded capital expenditures by about $500 million. In 2001, our cash margin will very likely exceed our capital requirements again. The most attractive option, when available, is to reinvest the excess cash in high rate-of-return oil and gas projects. A significant discovery on one of our prospects in the deepwater Gulf of Mexico or offshore West Africa could require hundreds of millions of dollars to fully develop. In addition, with consolidation accelerating in our industry, we will likely have opportunities to make attractive acquisitions.

The most obvious action for a highly leveraged company would be to continue to repay debt. However, Devon already has one of the strongest balance sheets among independent oil and gas producers. We entered 2001 with net debt of only 27% of total capital. In addition, some of our current indebtedness has early repayment penalties that are too costly to justify. We will repay debt when it is financially prudent to do so, but we will not aggressively repay debt if we judge the costs to be too high.

Another possible use for excess cash is repurchasing stock. In early 2001, Devon initiated a program to buy back up to two million common shares from holders of less than 100 shares. This program serves two purposes. By reducing the number of shares outstanding, each remaining shareholder’s stake in the company is increased. In addition, eliminating small accounts with just a few shares of stock reduces administrative costs.

What is Devon's international strategy?

Michael Lacey, Senior Vice President – Exploration and Production:

Because the majority of the world's remaining undiscovered oil and gas reserves lie outside North America, we elected to establish an international presence. However, we recognized that establishing a meaningful international position through grass roots exploration takes many years. It requires significant capital investment far in advance of any likely returns.

Devon is entering the international arena in the same way that we established significant positions in most of our North American core areas. Through mergers completed over the last two years, we have acquired footholds in several areas outside North America. We have taken years off the lead time that would otherwise have been required. In just two years we have established operations in South America, West Africa, Asia and Indonesia. We have knowledgeable and experienced staff in these areas as well as working relationships with the host governments. Devon and our shareholders have been spared considerable lead time and capital investment.

The international assets assembled by PennzEnergy and Santa Fe Snyder are of varying quality and stages of maturity. In addition, some of these assets were accompanied by drilling and capital commitments. We will honor these commitments and learn as much as possible about the opportunities and risks in each area. Our assets outside North America will ultimately be judged on the same criteria by which we evaluate all opportunities. Devon chooses to compete in areas where we have, or believe that we can establish critical mass, and the resulting economies of scale. A project area must have the potential to reach sufficient size to be meaningful to the company as a whole. We also prefer to operate in areas that provide a relatively stable political environment, a reasonable fiscal regime and access to strong or growing oil and gas markets.

Our ultimate goal is to establish significant oil and gas production in a few select international areas. We expect to divest our holdings in some areas, build upon the assets we retain in others and possibly establish ourselves in some new areas.

The past year saw record high prices for natural gas and concerns about supply shortages. Are we running out of natural gas?

Larry Nichols:

No. Studies indicate that abundant supplies of undiscovered natural gas remain throughout North America. However, much of this gas lies beneath public lands. The U.S. government has restricted the energy industry's access to public lands for drilling while at the same time encouraging the consumption of clean, efficient natural gas. The result of these contrary policies was predictable and inevitable. Yet, three years of unusually warm winters masked the signs of declining natural gas deliverability. The cold weather early in the winter of 2000-2001 finally caused supply and demand forces to collide. Gas prices soared.

The current situation is severe enough to suggest that natural gas supply and demand may be in tight balance for the next few years. Unlike crude oil, which can be easily transported around the world in tankers, natural gas is transported almost exclusively by pipelines. That means we must look to North America to satisfy the vast majority of our needs for natural gas. High gas prices will cause the oil and gas industry to increase drilling. More drilling in existing producing areas alone, however, may not result in enough new supply to ease the current pinch. Access to public lands can make a difference. The recent natural gas price shocks will bring this issue to the political forefront. We encourage our government to ease access to public lands to allow the industry to develop our continent's vast untapped natural gas resources.

From an administrative perspective, what were your greatest challenges in integrating PennzEnergy and Santa Fe Snyder into Devon?

Marian Moon, Senior Vice President – Administration:

From my perspective, our toughest challenge was integrating the myriad of management information systems, human resources policies and employment benefit programs. Our goal was to take the best from each organization and integrate them while maintaining a competitive cost structure.

The three organizations had a wide variety of management information systems. Some were good, some were inadequate and some were duplicative or redundant. We are thoroughly evaluating and testing every system. We are trying to be as open minded as possible, not giving preference to the Devon systems just because we are familiar with them. We want to build an integrated information network that will be compatible, cost effective and will provide reliable and timely management reporting tools. I believe that we have succeeded in establishing the process to accomplish our goals. We are well on the way to having a management reporting system that will be among the best in our industry.

On the human resources side, the challenge was to provide Devon's employees with a competitive, yet cost effective, package of benefits. While some fine tuning remains, this process is essentially complete. Devon has adopted a comprehensive package of employee benefits and human resources policies and procedures consistent with the needs of a large independent. We are well positioned to compete for and retain the employee talent necessary to sustain our growth profile. Furthermore, our general and administrative costs remain among the lowest in the industry.

Having completed three major mergers and acquisitions in three years, does Devon still have an appetite for acquisitions?

Larry Nichols:

Yes, we continually look for opportunities to complete value-added mergers and acquisitions. We have refined the process of identifying and executing mergers and acquisitions into a core competency. As a result, we are often on the short list of potential buyers when opportunities arise.

We are dedicated to achieving very clear strategic goals. We strive to establish large, focused positions in areas where we can earn a high rate of return. Acquisitions are a means to achieve this goal.

An example is our entry into Canada. In the early 1990's we identified Canada as a desirable area for Devon's expansion. We believed that the Western Canadian Sedimentary Basin held exploration promise. In addition, we expected the developing gas-transportation infrastructure from Canada to robust U.S. gas markets would improve the profitability of Canadian production. In 1996, we established a foothold with our acquisition of Kerr McGee's North American onshore properties. While most of the properties acquired were in Devon's historical U.S. focus areas, the acquisition also included a small operation in Canada. In 1998, we leveraged our experience and built on this position with our merger with Northstar Energy. In just two years, we had become a significant and profitable factor in the Canadian oil and gas business. We have an experienced staff, a growing exploration program and we are well positioned to pursue additional acquisitions should the opportunity arise.

Alternatively, we could have opened a Canadian office, started leasing acreage, and built a Canadian division from the ground up. This would have likely been an expensive proposition for Devon's shareholders. It would have taken years to establish a significant position, learn the ropes and begin realizing a return on our investment.

We will continue to look to mergers and acquisitions as part of our larger strategy. We will remain disciplined and when the right opportunities become available, we will utilize mergers and acquisitions to expand our presence in established core areas and to jumpstart moves into new ones.

Social, Environmental, Health and Safety Philosophy.

Devon Energy Corporation recognizes our obligation to conduct our business lawfully, ethically, and in a socially and environmentally responsible manner. We strive to achieve a high level of performance in each of these areas. The prevention of accidents, respect for the environment, and promotion of safe working conditions at the company's work locations is a long-established company philosophy. Our greatest assets in applying this philosophy are well informed and highly committed employees working together to meet or exceed government and industry standards. Achievement of this level of performance is primarily the responsibility of supervisors within each operating unit. However, every employee and contractor is expected to work safely, in a manner compatible with the natural environment, and to promptly report environmental, health or safety-related incidents. Participation and adherence to this philosophy is a requirement for Devon employees.

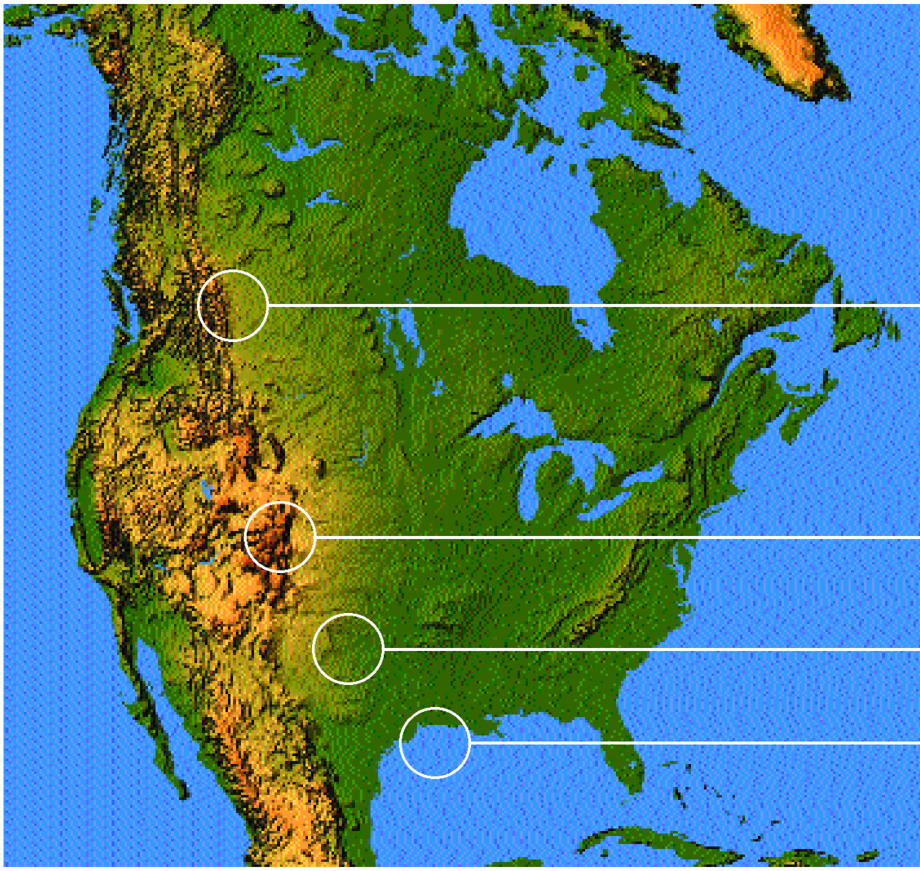

UNITED
GULF
OF

The right assets.

Devon has managed its portfolio of oil and gas properties to provide a stable platform for future growth. We have concentrated our properties to achieve economies of scale and high operating margins while providing a growing inventory of future drilling opportunities. We have focused our assets in the areas where we can be most competitive. By concentrating our properties, we have become a dominant operator in most of our producing areas. This makes Devon an important customer to drilling, service and supply companies. It translates to greater purchasing power, better service and lower costs. Concentrating our oil and gas production also gives us marketing clout, resulting in higher prices for the oil and natural gas we sell. An additional benefit of a highly concentrated asset base is the development of regional expertise. Our geologists, geophysicists and engineers become intimately familiar with the geologic and operating characteristics of a region. As a result, we have a competitive advantage, both in optimizing current operations and in identifying additional growth opportunities. Devon's property base yields a source of high-return investment opportunities and a stable source of cash flow with which to pursue these opportunities.

We have organized our operations geographically into five separate divisions. Each of Devon's operating divisions is staffed by a team of geoscientists, engineers, land professionals and support personnel in the division offices and in the field. Each division controls an underlying base of producing oil and gas wells and an inventory of undeveloped lands on which to explore for new oil and gas reserves. We conduct operations in the U.S. through our Permian/Mid-Continent, Rocky Mountain and Gulf divisions. Our Calgary, Alberta-based Northstar subsidiary, conducts our operations in Canada and our operations outside North America are directed through our International Division.

PRIMARY OPERATING AREAS



PERMIAN / MID-CONTINENT DIVISION

The Permian/Mid-Continent Division encompasses southeast New Mexico, north, east and west Texas, Oklahoma, Arkansas, Mississippi and northern Louisiana. With more than a fourth of the company's proved reserves and almost one-third of current oil and gas production, it is our largest division. Current production is about one-half oil and one-half natural gas.

Although the Permian/Mid-Continent area was home to some of the earliest oil and gas discoveries in the United States, the area continues to offer many exploration and low-risk development opportunities. In 2000, we drilled 175 net wells in the Permian/Mid-Continent with a 98% success rate. These wells replaced more than 160% of the division's oil and gas production with new reserve additions.

In 2001, we are stepping up our activity in the Permian/Mid-Continent with plans to drill more than 200 net wells. About 40 of these wells are planned in the Carthage, Bethany, Sligo area of east Texas and north Louisiana. Many of these wells will extend the limits of producing reservoirs as well as test shallower and deeper undeveloped horizons. We also plan to increase reserves and production in this area through downspacing. Downspacing, or drilling wells closer together within producing fields, is predictable, low-risk drilling. Over time, we have decreased well spacing in the Carthage, Bethany, Sligo area from 640 acres per well to as little as 40 acres per well. We have increased production in this area five-fold since the early 1980's. This activity has also added significant reserves.

Devon holds more than 300,000 net undeveloped acres in north Louisiana. Most of this acreage was acquired in our 2000 merger with Santa Fe Snyder. This acreage holds exploration potential for the traditional Hosston and Cotton Valley gas reservoirs at 9,000 to 12,000 feet. In addition, significant upside may exist in both deeper zones such as the Bossier and shallower coal formations. We will begin testing the potential of this acreage with exploratory wells during 2001.

Another example of our exploration activities in the Permian/Mid-Continent area is our Maben Field. This field lies on the eastern edge of the Permian/Mid-Continent Division in the Black Warrior Basin of Mississippi. In 1998, Devon and an industry partner made a 100 billion cubic feet natural gas discovery in the Knox formation at a depth of about 15,000 feet. We have continued to develop this discovery with two successfully completed development wells and another currently drilling. In 2001 we plan to drill two more development wells at Maben. In addition, we have identified numerous leads on similar structures. We are acquiring additional acreage and during 2001 we plan to begin testing these new prospects with exploratory wells.

ROCKY MOUNTAIN DIVISION

The Rocky Mountain Division includes northern New Mexico and the states of Colorado, Utah and Wyoming. This gas-prone area comprises 24% of Devon's proved oil and gas reserves and generated 16% of 2000 production. With production expected to increase about 30% in 2001, this is Devon's fastest growing division.

Much of our 2001 production growth in the Rockies will result from expansion of our coalbed methane projects. Coalbed methane, or CBM, is natural gas produced from underground coal deposits. Our CBM production is characterized by minimal drilling risk, low development costs, low operating costs and a long economic life. It differs from conventional natural gas in that production generally starts out low and increases throughout the early life of the wells. As the water is pumped out of the coal, the well is "dewatered" and gas production increases.

Devon was a pioneer in the development of CBM technology. In the mid-1980's, Devon advanced one of the first and most successful CBM projects in the world—the Northeast Blanco Unit. Fifteen years later, this property in the San Juan Basin of northwestern New Mexico is still producing at very high rates. It is expected to produce significant quantities of natural gas for decades to come.

Due to the low drilling risk and desirable economics of our CBM production, Devon has applied the experience gained in the San Juan Basin to other CBM projects throughout the Rocky Mountains. We have large-scale CBM projects underway and we are gathering data and leasing acreage in areas prospective for CBM development.

In 1998, we began to develop CBM in the Powder River Basin of northeast Wyoming. Our 250,000 net acres in the basin makes us one of the largest operators in Wyoming. Through the end of 2000, we had drilled over 600 Powder River CBM wells. At the end of 2000, Devon's production from these wells was about 60 million cubic feet per day and climbing. In 2001, our production is expected to average 90 to 100 million cubic feet per day. We plan to drill more than 1,000 additional wells here over the next few years. With nearly three-quarters of our lands still undeveloped and an estimated net resource potential of a trillion cubic feet of gas, we expect the Powder River to be an important source of production and reserve growth for years to come.

Devon is also developing CBM production in the Raton Basin of northeast New Mexico and southeast Colorado. Devon has an interest in 280,000 acres with CBM potential in the Raton Basin, giving us one of the largest positions in the play. Our economics here are enhanced by an arrangement with an industry partner. This joint venture allows Devon to receive over 40% of the revenue while bearing only 25% of the capital costs. We drilled 89 wells in this project during 2000 and expect to drill about 100 wells in each of the next few years. As these wells dewater, production is climbing and just beginning to reach meaningful rates. Early indications are that the Raton Basin will become another important CBM source for Devon. Although it is too early to determine the ultimate degree of success, Devon's net resource potential in the Raton Basin is estimated to range from 500 billion to one trillion cubic feet of natural gas.

During 2000, we began to test the potential for CBM production on our acreage in the Beaver Creek area of Wyoming's Wind River Basin. While this area is known primarily for production from conventional reservoirs, multiple coal formations underlie our 50,000 net acres. In 2000, we drilled five CBM wells to test the potential. These wells are in the early stages of dewatering and we are monitoring the results closely. Should the pilot program prove successful, we will aggressively develop this resource.

Although CBM is the fastest growing resource in the Rocky Mountain Division, conventional wells still account for more than half of the gas produced within the division. Our Washakie Field in south central Wyoming is Devon's largest conventional gas area. In 2000, we drilled 58 Washakie wells with 100% success. We plan to drill 70 wells here during 2001. With over 200,000 net acres and up to 400 undrilled locations, we will be actively developing the Washakie for many years to come.

GULF DIVISION

The Gulf Division conducts oil and gas exploration and production operations offshore in the Gulf of Mexico and onshore in south Texas and south Louisiana. The division accounts for 11% of Devon's total proved reserves and contributed 32% of 2000 production. Production is about two-thirds gas, providing Devon with significant exposure to this premium natural gas market. Offshore operations account for over 80% of reserves and production within the Gulf Division. In terms of capital allocation, Devon has earmarked 30% of its 2001 drilling and facilities budget for the Gulf Division, with over two-thirds of that planned for offshore projects.

Gulf - Shelf

The Gulf of Mexico is comprised of two major operating areas, as defined by water depth. In the shelf area, with water depths up to 600 feet, Devon is one of the 10 largest oil and gas producers. The shelf is a relatively mature producing region that is a vital source of U.S. natural gas supply. Devon's shelf wells produce around 70,000 net barrels of oil equivalent per day. We hold approximately 650,000 net acres on the shelf, about one-half of which is developed.

Our shelf strategy emphasizes exploitation — drilling for new reserves close to existing producing facilities. We are often able to quickly tie-in new wells to our existing infrastructure. This improves our overall project economics. Devon's shelf exploitation success has been enhanced through the application of advanced technology in seismic, drilling and completion methods. We are currently pioneering the use of four-component, or "4C" seismic in two areas on the shelf. This developing technology greatly improves the resolution of seismic images below shallow gas deposits. These shallow gas "clouds" tend to inhibit the imaging of deep structures with conventional 3D seismic techniques. Last year we acquired over 300 square miles of 4C seismic data in the West Cameron area, offshore Louisiana. We estimate the unrisked potential gas reserves on our acreage underlying this 4C data to be 300 billion cubic feet. New 4C data is currently being acquired in the Eugene Island area, also offshore Louisiana. At West Cameron block 587, Devon is employing horizontal drilling. This advanced drilling technology allows us to economically develop relatively thin shallow gas formations from our existing platforms.

Our shelf strategy employs exploration drilling in addition to exploitation. While the distinction between exploitation and exploration can be subtle, exploratory wells generally have a higher risk/reward profile. During 2000, we made several exploration discoveries on the Gulf shelf. These include Eugene Island block 156. This discovery began producing in October at over 50 million cubic feet of gas and 1,600 barrels of condensate per day. Also included is what appears to be a significant oil and gas discovery at High Island A-582. A second well to further delineate this discovery was successful and a third well is currently drilling. First production is expected in 2002, following installation of a new producing platform.

In 2001, we expect to drill 35 wells on the shelf. While most of these will be lower-risk exploitation and development wells, we plan to drill five to eight high-potential shelf exploration wells.

This deepwater drilling rig is used in water depths up to 2,000 feet. In 2001, we plan to participate in at least two exploration wells in the deepwater of the Gulf of Mexico.

Gulf - Deepwater

While the shelf is relatively mature, the deepwater Gulf is a promising frontier area. The deepwater Gulf is believed to hold some of the largest remaining undiscovered reserves in North America. A developing infrastructure and recent advances in technology have opened the deepwater to exploration by independent oil and gas companies. Devon holds approximately 400,000 net acres in the deepwater Gulf of Mexico of which about 90% is unexplored. Because deepwater exploration is capital intensive, our strategy is to move cautiously. We avoid ultra-deepwater and focus our efforts on prospects in water depths for which infrastructure and production technology are well established. We participate with industry partners, retaining smaller interests in each project to further mitigate risk. We also limit our participation to no more than four deepwater exploratory wells each year.

In 2000, Devon participated in two deepwater discovery wells. While these discoveries, Pecten and Maria, lie in deepwater, they are close enough to be tied back to our Main Pass block 259 facilities on the shelf. We expect to tie-in these discoveries in 2001.

In the first half of 2001, we will begin drilling the Mt. Massive prospect on Garden Banks block 600, offshore Louisiana. This prospect, with an estimated gross well cost of $25 million, lies in 3,200 feet of water. Estimated total depth of the test well is 24,000 feet. Mt. Massive is in the prolific Auger Basin where Devon has already established deepwater production. Reserve potential for Mt. Massive exceeds 80 million barrels of oil equivalent and we hold a 25% working interest.

In late 2001 or early 2002, we expect to initiate drilling of the Cortes Prospect on Port Isabel block 175, offshore Texas. The Cortes prospect lies in 3,300 feet of water. The estimated total depth of the well is 18,000 feet with an estimated gross well cost of $24 million. Devon has a 25% working interest in this prospect. Cortes is one of the largest untested structures remaining in the Gulf of Mexico. It has estimated unrisked reserve potential of 250 million barrels of oil equivalent. Either of these two wells, if successful, has the potential to significantly increase Devon's deepwater reserves.

Gulf Onshore

Devon holds about 300,000 net acres onshore in south Texas and south Louisiana. About 80% of that acreage is developed for oil and gas production. Most of our acreage in this area was acquired in Devon's 1999 merger with PennzEnergy. Since this was not a focus area for PennzEnergy, this acreage was underdeveloped. During 2000, we stepped up activity with the drilling of 34 wells. Based on the success of the 2000 program, we will almost double that number in 2001 to an estimated 62 wells.

One area we are actively pursuing is Ray Ranch in south Texas. In 2000, we evaluated the results of a new 3D seismic survey over the ranch. Based on the potential we saw, we have been acquiring additional acreage. We drilled three successful wells at Ray Ranch in 2000 and plan to drill a dozen more in 2001.

Another notable Gulf onshore discovery during 2000 was in the Patterson Field in south Louisiana. Devon's Zenor A-16 logged 250 feet of pay and tested over 20 million cubic feet of gas per day. Our interest in this well is 50%.

CANADIAN DIVISION

Devon's Canadian operations are conducted through Northstar Energy, our subsidiary headquartered in Calgary, Alberta. Canada accounted for 12% of Devon's proved reserves at year-end 2000 and 13% of 2000 oil and gas production. On a stand-alone basis, Devon's Canadian operations would rank twelfth among Canadian independent producers. Our Canadian production is approximately two-thirds natural gas. About 15% of Devon's total 2001 budget for drilling and facilities is dedicated to Canada, and 85% of that is related to exploration for and development of natural gas.

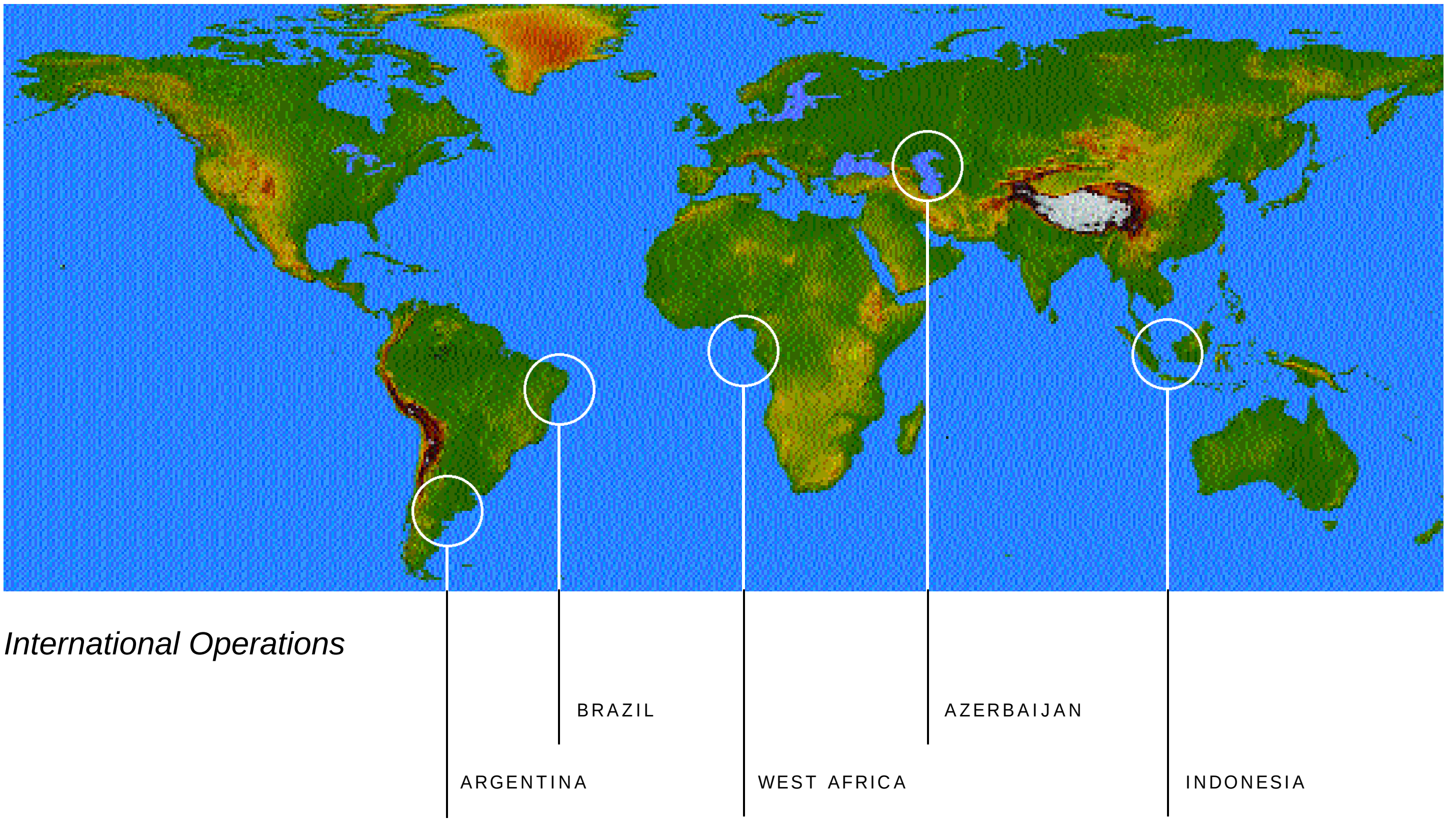
Over a third of Devon's Canadian oil and gas reserves are located in the shallow gas areas of northern Alberta. This is where we will do the majority of our drilling in Canada in 2001. In most of these shallow gas areas, drilling is restricted to the winter months of December through March. This is because the soft, wet ground must be frozen to allow access to heavy drilling equipment. Wells here range between 1,000 and 2,500 feet in depth and can be drilled quickly and inexpensively. Devon has become very efficient at drilling shallow gas wells in Alberta, and over the past three years we have cut average drilling costs in half. We expect to drill more than 100 shallow gas wells in the winter-only access areas of northern Alberta during 2001.

Devon also has an aggressive exploration program underway on our more than two million net undeveloped acres in Canada. Our highest potential project area is the northern foothills of British Columbia and Alberta. We hold 248,000 acres with an average working interest of 47%. We are currently drilling two deep gas wells in the northern foothills following a significant gas discovery on the Weejay prospect in 1998. Wells in this area range between 6,000 and 15,000 feet in depth and the deeper wells can take many months to drill and test. Exploration targets range up to 300 billion cubic feet of natural gas each, so discoveries can significantly increase reserves and production. In 2001, Devon will test five new structures in the northern foothills and acquire additional exploration acreage. The Weejay discovery, which produced over 20 million cubic feet of gas per day during testing, will commence production in late 2001 or early 2002.

A promising longer-term avenue for increasing gas production in Canada is coalbed methane. There is little or no commercial coalbed methane production in Canada today. However, the rapid growth of coalbed methane production in the U.S. suggests that such developments in Canada may be close at hand. Devon is an industry leader in producing gas from coal deposits in the Rocky Mountains. Devon's Rocky Mountain and Canadian divisions are teaming up to share expertise acquired south of the border. We have identified several areas in Canada that are prospective for coalbed methane exploration. To date, we have acquired 39,000 net acres with underlying coal deposits. Devon's early entry into Canadian coalbed methane exploration and development may give us a first-mover advantage.

Mineral Revenues Stewardship Award

For the fourth consecutive year Devon's Accounting Department received the United States Department of Interior Mineral Revenues Stewardship Award in 2000. This award recognizes those companies with the lowest error rates, most timely payments and utmost responsiveness to compliance and enforcement requests. More than 1,600 companies report to the Minerals Management Service. Devon was one of only two oil and gas companies to receive the Stewardship Award in 2000.



International Operations

INTERNATIONAL DIVISION

Approximately 25% of Devon's proved reserves are located outside North America. Most of these international reserves are concentrated in three countries: Azerbaijan, Indonesia and Argentina. Although a quarter of Devon's reserves are located outside North America, international production was just 9% of the company's total production in 2000. This reflects both the relative immaturity of our international operations and the long lead times often required in bringing international discoveries to market. Because natural gas markets outside North America are generally not well developed, Devon's international efforts are focused predominantly on oil. However, as natural gas markets develop, we expect natural gas to become a growing part of our international production mix.

We plan to deploy about $270 million of our 2001 capital budget in the International Division. A full one-third of that amount will be directed toward higher risk/reward exploration projects with the potential to substantially increase reserves. Because most of North America's oil and gas producing basins are more mature than those found abroad, international basins have far greater potential for large oil and gas discoveries.

Devon holds 12 million net acres of undeveloped lands in 13 countries outside North America. Some of the most exciting prospects on these lands lie under the waters of coastal West Africa. Devon holds substantial land positions offshore Ghana, Gabon and Congo where we have active exploration programs underway. Through a joint venture with another large U.S. independent, we will be conducting seismic surveys and drilling exploratory wells on these blocks over the next few years. In addition to our exploration in West Africa, we plan to drill exploratory wells in Egypt, China, Malaysia, Argentina and Brazil in 2001 and 2002.

At the end of 2000, approximately 37% of our proved reserves outside North America were in Azerbaijan, located offshore in the Caspian Sea. Devon now has a 5.6% interest in the Azeri-Chirag-Gunashli (ACG) oil field, including 0.8% acquired in February 2001. The ACG field is believed to contain over 4 *billion* barrels of proved reserves, making it one of the largest oil fields in the world. Devon is in partnership with major international oil companies in developing the ACG field. Under the terms of Devon's participation, one of these companies pays our share of current capital costs. Development of the ACG field is constrained today by the lack of adequate export pipelines from the region. When adequate pipeline systems are in place, Azerbaijan will become a significant supplier of crude oil to world markets and a significant producing asset for Devon.

Devon's second largest international area is in Indonesia. Our current production here is primarily oil and natural gas liquids—about 13,000 barrels per day. However, in February 2001, Devon signed a groundbreaking 20-year agreement to supply Indonesian natural gas to nearby Singapore. This paves the way to begin producing our extensive gas reserves on the island of Sumatra. Deliveries to Singapore should begin by 2003 following construction of an export pipeline. Initially, Devon's share of production will be about 26 million cubic feet of gas per day. This will increase to 48 million cubic feet per day when production peaks in 2009. The gas sales will have the added benefit of increasing our liquids production as well. Because the gas to be sold to Singapore is rich in natural gas liquids and oil-like condensate, the liquids will be removed from the gas and sold separately. Devon will gain another 4,000 barrels per day of liquids sales when gas production begins. The sales price of gas to be delivered to Singapore is based on the price of the fuel oil it will replace. Had the contract been in effect in 2000, the price received for this gas would have been about $4 per thousand cubic feet.

Another significant concentration of Devon's international reserves lies in Argentina. Our reserves in Argentina are about two-thirds natural gas and one-third oil. The development of natural gas markets in Argentina and in neighboring Chile and Brazil is improving the profitability of production in this part of South America. Our current development efforts are focused in the Neuquen Basin of central Argentina. In early 2000, we acquired a 100% working interest in the El Mangrullo block. We believe we can establish production from this block by developing the El Tordillo formation. In addition, we plan to develop a shallower formation that is productive in other parts of the Neuquen Basin. A recent 3D seismic program over the area will guide these development efforts.

A key element of our international strategy is to bring focus to these operations and build critical mass in the areas where we can be most competitive. Accordingly, Devon will ultimately surrender positions in some of the 13 countries in which we now have interests. The results of this year's drilling program will begin to answer many open questions.

A worker maintains an oil field road in Indonesia. In early 2001, Devon signed a groundbreaking agreement to supply Indonesian natural gas to Singapore.

Corporate Leadership Award

Blaine Wofford, a Devon marketing manager, was awarded the 2000 Corporate Leadership Award by the United States Department of Interior Minerals Management Service. This honor is presented to oil and gas professionals who enhance the agency's ability to achieve its objectives.

Blaine was recognized for assisting the Minerals Management Service with its Gulf of Mexico Royalty-in-Kind gas pilot project. He worked closely with the Minerals Management Service to resolve operational, transportation and processing issues involving Devon's federal offshore properties. He provided valuable insight and knowledge by mentoring Minerals Management Service employees who had little or no previous experience in the marketing and movement of natural gas. Blaine's conduct exemplifies the cooperative working relationship Devon continually strives to foster with regulatory agencies and all of our business partners.

OPERATING STATISTICS BY AREA

		PERMIAN BASIN	MID-CONTINENT	TOTALPERMIAN/ MID-CONTINENT	ROCKY MOUNTAINS	ONSHORE GULF	OFFSHORE GULF
Producing Wells at Year-End		14,315	3,548	17,863	3,397	754	1,010
2000 Production (Net of Royalties):							
Oil (MBbls)		11,876	2,082	13,958	2,928	838	10,838
Gas (MMcf)		57,675	56,740	114,415	91,699	23,673	125,300
Natural Gas Liquids (MBbls)		1,933	2,204	4,137	693	320	1,552
Total (Mboe) (1)		23,421	13,743	37,164	18,904	5,104	33,273
Average Prices:							
Oil Price ($/Bbl)	$	23.36	26.48	23.82	27.96	29.59	26.54
Gas Price ($/Mcf)	$	3.59	3.72	3.66	3.38	3.71	3.90
Natural Gas Liquids Price ($/Bbl)	$	19.39	19.82	19.61	20.70	20.84	21.83
Year-End Reserves (Net of Royalties):							
Oil (MBbls)		120,162	12,417	132,579	45,618	4,133	43,207
Gas (MMcf)		318,295	503,723	822,018	1,248,534	90,549	360,206
Natural Gas Liquids (MBbls)		19,786	19,489	39,275	4,495	1,350	398
Total (Mboe) (1)		192,997	115,860	308,857	258,202	20,575	103,639
Year-End Present Value of Reserves (Thousands): (2)							
Before Income Tax	$	2,645,957	2,316,626	4,962,583	4,796,594	539,027	3,098,340
After Income Tax							
Year-End Leasehold (Net Acres):							
Producing		370,590	415,434	786,024	308,355	247,918	383,338
Undeveloped		392,002	608,861	1,000,863	1,493,846	54,047	653,282
Wells Drilled During 2000		244	78	322	598	33	56
2000 Exploration, Development & Facilities Expenditures (Millions) (3)	$	122	66	188	147	50	233
Estimated 2001 Exploration, Development & Facilities Expenditures (Millions) (4)	$	125 - 140	75 - 90	200 - 230	110 - 140	85 - 105	210 - 250

(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% in accordance with Securities and Exchange Commission guidelines.
(3) Excludes $40 million for construction of gas gathering system in Powder River Basin.
(4) Excludes $15 to $20 million for construction of gas gathering system in Powder River Basin.

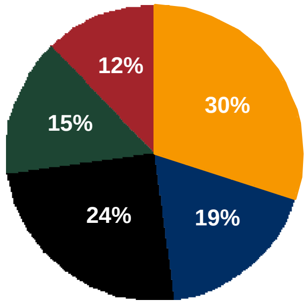
ELEVEN YEAR PROPERTY DATA

		1990	1991	1992	1993
PROVED RESERVES (net of royalties):					
Oil (MBbls)		231,093	235,881	279,562	273,697
Gas (MMcf)		387,648	410,286	645,163	736,381
Natural Gas Liquids (MBbls)		1,656	3,498	6,721	7,186
Total (MBoe) (1)		297,357	307,760	393,810	403,613
SEC @ 10% Present Value (Thousands) (2)	$	1,492,057	811,870	1,376,081	1,097,655
PRODUCTION (net of royalties):					
Oil (MBbls)		20,459	21,887	26,235	29,782
Gas (MMcf)		48,091	51,737	80,460	106,478
Natural Gas Liquids (MBbls)		332	340	660	1,115
Total (MBoe) (1)		28,806	30,850	40,305	48,643
AVERAGE PRICES:					
Oil (Per Bbl)	$	17.33	16.04	14.94	13.12
Gas (Per Mcf)	$	1.50	1.41	1.63	1.77
Natural Gas Liquids (Per Bbl)	$	14.15	16.39	12.57	11.75
Oil, Gas and Natural Gas Liquids (Per Boe) (1)	$	14.98	13.93	13.18	12.18
PRODUCTION AND OPERATING EXPENSE PER BOE (1)	$	6.09	5.86	5.35	5.04

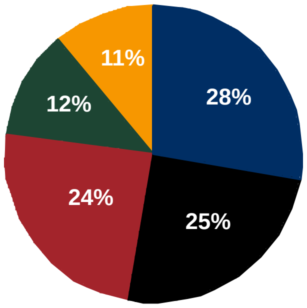
(1) Gas converted to oil at the ratio of 6 Mcf:1 Bbl
(2) Before income taxes

TOTAL GULF	TOTAL U. S.	CANADA	INTERNATIONAL	TOTAL COMPANY
1,764	23,024	2,911	995	26,930
11,676	28,562	4,760	9,239	42,561
148,973	355,087	62,284	8,775	426,146
1,872	6,702	682	16	7,400
38,377	94,445	15,823	10,717	120,985
26.76	25.45	24.46	25.48	25.35
3.87	3.67	2.71	1.32	3.49
21.66	20.30	26.51	21.19	20.87
47,340	225,537	36,492	197,215	459,244
450,755	2,521,307	523,509	413,368	3,458,184
1,748	45,518	4,204	12,035	61,757
124,214	691,273	127,948	278,145	1,097,366
3,637,367	13,396,544	2,935,656	1,404,843	17,737,043
	9,629,348	1,777,157	1,065,682	12,472,187
631,256	1,725,635	539,904	101,525	2,367,064
707,329	3,202,038	2,228,510	12,195,069	17,625,617
89	1,009	233	86	1,328
283	618	128	158	904
295 - 355	605 - 725	155 - 195	240 - 300	1,050 - 1,150

2001 DRILLING & FACILITIES BUDGET BYDIVISION

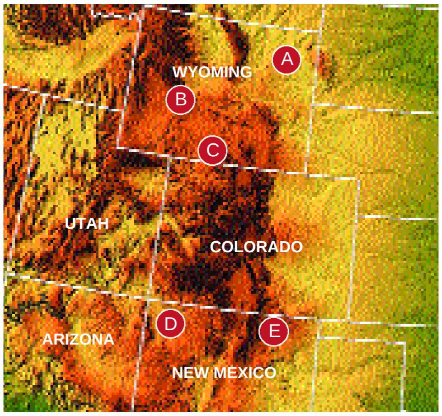


PROVED OIL & GAS RESERVES BYDIVISION



Permian / Mid-Continent
Rocky Mountains
Canada
Gulf
International

1994	1995	1996	1997	1998	1999	2000	5-YEAR COMPOUND GROWTH RATE	10-YEAR COMPOUND GROWTH RATE
311,944	333,699	375,355	218,741	235,457	496,717	459,244	7%	7%
781,560	894,846	1,157,719	1,403,204	1,476,994	2,949,627	3,458,184	31%	24%
11,965	16,050	18,490	24,478	32,679	67,817	61,757	31%	44%
454,169	498,890	586,798	477,086	514,302	1,056,139	1,097,366	17%	14%
1,561,239	1,985,953	4,095,248	2,100,344	1,527,539	5,811,723	17,737,043	55%	28%
30,001	30,630	33,180	32,565	25,628	31,756	42,561	7%	8%
101,309	112,934	123,286	186,239	198,051	304,203	426,146	30%	24%
1,220	1,531	2,055	2,842	3,054	5,111	7,400	37%	36%
48,106	50,983	55,783	66,447	61,691	87,568	120,985	19%	15%
13.12	15.14	17.62	17.05	12.10	17.67	25.35	11%	4%
1.69	1.43	1.79	2.01	1.75	2.06	3.49	20%	9%
10.41	10.06	13.97	12.61	8.09	13.30	20.87	16%	4%
12.00	12.58	14.95	14.54	11.05	14.35	22.47	12%	4%
4.95	4.85	5.31	4.78	4.45	4.31	4.94	—	(2%)



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'.
- 25.8 million barrels of oil equivalent reserves at 12/31/00.

2000 Activity
- Drilled 410 coalbed methane wells (more than 250 wells awaiting connection to transportation system at year-end).
- Increased net production four-fold.
- Acquired 5,000 net acres of undeveloped exploratory Big George coal seam acreage.

2001 Plans
- Connect remaining wells drilled in 2000 to transportation system.
- Drill 300 to 500 additional coalbed methane wells.
- Drill second pilot program testing Big George formation.

B - Wind River Basin

Profile
- 94% working interest in 83,000 acres in Central Wyoming.
- Obtained in 2000 merger.
- Produces conventional gas from multiple formations at 7,000' to 9,000'.
- 43.3 million barrels of oil equivalent reserves at 12/31/00.

2000 Activity
- Drilled and completed 11 conventional wells.
- Initiated 3 additional conventional wells.
- Performed 8 recompletions.
- Drilled a 5 well coalbed methane pilot.

2001 Plans
- Continue drilling conventional wells initiated in 2000.
- Drill 7 to 10 additional conventional development wells.
- Initiate gas plant upgrades and modifications.

C - Washakie

Profile
- 70% working interest in 230,000 acres in southern Wyoming.
- Obtained in 2000 merger.
- Produces gas from multiple formations at 6,800' to 10,300'.
- 66.1 million barrels of oil equivalent reserves at 12/31/00.

2000 Activity
- Drilled and completed 58 gas wells.
- Performed 10 well workovers and recompletions.

2001 Plans
- Drill and complete 55 gas wells.
- Perform 10 well workovers and recompletions.

D - NEBU/32-9 Units

Profile
- 25% working interest in 50,000 acres in the San Juan Basin of northwestern New Mexico.
- Development began in the late 1980s and early 1990s.
- Includes 168 coalbed methane wells, gas and water gathering systems and an automated production control system.
- Produces coalbed methane from the Fruitland Coal formation at 3,000'.
- 35.1 million barrels of oil equivalent reserves at 12/31/00.

2000 Activity
- Expanded the capacity of the La Jara gas gathering system.
- Upgraded electrical system.
- Recavitated 36 wells.
- Installed 5 wellhead compressors.
- Installed 31 pumping units for water removal.

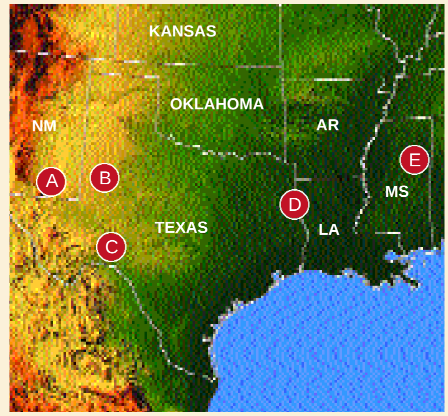
2001 Plans
- Recavitate 22 wells.
- Install 31 wellhead compressors.
- Install 73 pumping units for water removal.
- Continue electrical system upgrades.

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 merger.
- Produces coalbed methane from the Vermejo and Raton Coal formations at 1,000' to 2,300'.
- 23.6 million barrels of oil equivalent reserves at 12/31/00.

2000 Activity
- Drilled 79 coalbed methane wells.
- Drilled 4 water disposal wells.
- Drilled 8 core holes to further delineate formation.
- Began construction of main electrical transmission line.
- Expanded transportation system.

2001 Plans
- Drill 100 coalbed methane wells.
- Further expand gas transportation system.
- Expand main electrical transmission system.
- Drill 5 core holes and 4 stratigraphic test wells.



PERMIAN / MID-CONTINENT

A - Indian Basin

Profile
- 67% working interest in 15,000 acres in southeast New Mexico.
- Obtained in 1996 and 2000 transactions.
- Produces oil and gas from the Cisco Canyon formation at 7,500' to 8,000'.
- 15.1 million barrels of oil equivalent reserves at 12/31/00.

2000 Activity
- Drilled and completed 8 wells.
- Drilled 1 saltwater disposal well.

2001 Plans
- Drill 5 Cisco Canyon wells.
- Resolve pipeline, plant and power issues to allow for additional drilling.

B - Wasson Unit

Profile
- 25% net revenue interest in 7,800 acre unit in west Texas.
- Obtained in 2000 merger.
- Produces oil from the San Andres formation at 5,000'.
- 20.0 million barrels of oil equivalent reserves at 12/31/00.

2000 Activity
- Initiated pilot program in additional pay zone.
- Initiated infill drilling program.

2001 Plans
- Install additional compression to boost carbon dioxide injection.
- Continue infill drilling program.

C - Ozona

Profile
- 36% average working interest in 100,000 acres in southwest Texas.
- Purchased in 1992 and 1996 acquisitions.
- Produces gas from the Canyon and Strawn formations at 6,000' to 10,000'.
- 12.6 million barrels of oil equivalent reserves at 12/31/00.

2000 Activity
- Drilled 13 Canyon gas development wells.

2001 Plans
- Drill 8 Strawn development wells.
- Initiate recompletion program.

D - Carthage, Bethany, Sligo Area

Profile
- 75% to 100% working interest in 230,000 acres located in east Texas and north Louisiana.
- Acquired in 1999 merger.
- Produces from the Cotton Valley, Travis Peak and Pettit formations at 5,800' to 9,500'.
- Includes over 660 producing wells.
- 69.3 million barrels of oil equivalent reserves at 12/31/00.

2000 Activity
- Drilled and completed 42 infill wells.
- Completed 28 well recompletion/workover program.

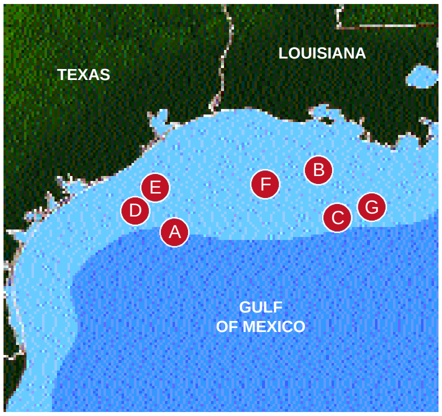
2001 Plans
- Drill and complete 37 exploitation wells.
- Drill 12 exploratory wells.
- Continue recompletion/workover program.

E - Mississippi Knox

Profile
- 43% to 50% working interest in 27,000 acres in northeastern Mississippi.
- Produces from the Knox formation at 15,000'.
- 3.7 million barrels of oil equivalent reserves at 12/31/00.

2000 Activity
- Drilled and completed 1 development well at Maben.
- Initiated drilling of additional development well at Maben.
- Evaluated seismic data and identified additional lead areas.
- Acquired acreage on new prospects.

2001 Plans
- Complete Maben development well initiated in 2000.
- Drill and complete 2 additional Maben development wells.
- Drill 2 exploratory wells on new prospects.
- Obtain additional seismic data.
- Acquire additional acreage.



GULF - SHELF

A - High Island 582

Profile
- 37% working interest.
- Obtained in 1999 merger.
- Located offshore Texas in 440' of water.
- Produces primarily gas from sands at 4,000' to 12,000'.
- 1.9 million barrels of oil equivalent reserves at 12/31/00.

2000 Activity
- Negotiated joint venture agreement with partners.
- Drilled Cyrus discovery well.

2001 Plans
- Drill 3 development wells off the 2000 discovery.
- Install new production platform and pipeline for initial production in 2002.

B - South Marsh Island 23 Area

Profile
- 100% working interest in Eugene Island block 156 and South Marsh Island blocks 22, 23, 34, 47 and 48; 50% working interest in South Marsh Island blocks 21 and 32.
- Obtained in 1999 merger.
- Located offshore Louisiana in 100' of water.
- 22 wells producing from the lower Pliocene/upper Miocene formations at 10,000' to 15,000'.
- 6.4 million barrels of oil equivalent reserves at 12/31/00.

2000 Activity
- Drilled 4 wells, 3 successful including the Eugene Island 156 discovery.
- Set new platform at Eugene Island 156.

2001 Plans
- Drill 3 wells.
- Recomplete/workover 6 wells.
- Install compression at South Marsh Island 23 G and 48 B.
- Reprocess 3D seismic at South Marsh Island 48.

C - Eugene Island 330 Area

Profile
- Includes 100% working interest in Eugene Island blocks 316 and 329; 50% in the south half of block 315; 23% in block 330.
- Obtained in 1999 merger.
- Located offshore Louisiana in 235' of water.
- Produces oil and gas from sands at 1,200' to 10,000'.
- 5.3 million barrels of oil equivalent reserves at 12/31/00.

2000 Activity
- Drilled 4 wells, 2 successful.
- Recompleted/worked over 5 wells.

2001 Plans
- Drill 4 wells.
- Recomplete/workover 8 wells.
- Reprocess 3D seismic at Eugene Island 316.
- Acquire 3D/4C seismic.

Shelf Exploration Prospects

Profile

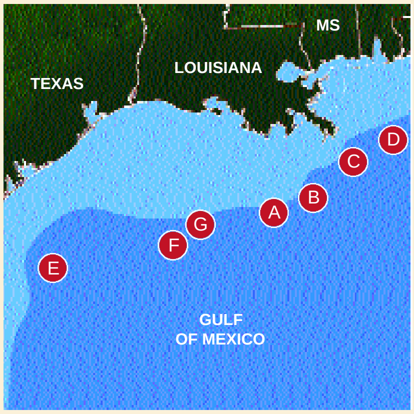
D - CRESTONE
- Galveston A82
- Located offshore Texas in 100' of water.
- Target formation: Miocene sands at 10,000' to 14,000'.
- Net unrisked reserve potential: 8.6 MMBoe.

E - GRAYS
- Galveston 424
- Located offshore Texas in 100' of water.
- Target formation: Miocene sands at 9,000' to 11,500'.
- Net unrisked reserve potential: 10.3 MMBoe.

F - SIGMA
- West Cameron 484 & 485
- Located offshore Louisiana in 150' of water.
- Target formation: Plio-Pleistocene sands at 14,000' to 17,000'.
- Net unrisked reserve potential: 14.6 MMBoe.

G - BONANZA
- Ship Shoal 275
- Located offshore Louisiana in 180' of water.
- Target formation: Pliocene sands at 12,000' to 15,000'.
- Net unrisked reserve potential: 5.8 MMBoe.

2001 Plans
- Finalize geophysical analysis.
- Bring in industry partners.
- Drill exploratory test wells.



GULF - DEEPWATER

A - Green Canyon Complex

Profile
- 100% operated working interest in Green Canyon 114 (Gretchen Discovery).
- 50% working interest in Green Canyon 112 & 113 (Angus Field).
- 50% working interest in Green Canyon 155 (Manatee Field).
- Obtained in 2000 merger.
- 24.4 million barrels of oil equivalent reserves at 12/31/00.

2000 Activity
- Determined development plan for Gretchen.
- Drilled 2 appraisal wells at Manatee.
- Opened new productive interval and improved production facilities at Angus.

2001 Plans
- Finalize development plans for Gretchen.
- Complete design of subsea system for Manatee.
- Produce and monitor Angus.

B - Ewing Banks 966

Profile
- 31% working interest in Ewing Banks 966 (Black Widow).
- Obtained in 2000 merger.
- Located offshore Louisiana in 1,850' of water.
- Produces oil and gas from the Basal Nebraskan formation at 11,700'.
- 1.2 million barrels of oil equivalent reserves at 12/31/00.

2000 Activity
- Constructed subsea and surface facilities.
- Placed field on production.

2001 Plans
- Produce and monitor well.

C - Mississippi Canyon 110

Profile
- 25% working interest in Mississippi Canyon 110 (Orion).
- Obtained in 2000 merger.
- Located offshore Louisiana in 1,200' of water.
- Produces oil and gas from multiple Pliocene sands at 6,000' to 7,000'.
- 1.9 million barrels of oil equivalent reserves at 12/31/00.

2000 Activity
- Drilled discovery well.
- Drilled development well.

2001 Plans
- Drill additional exploitation well and evaluate for future drilling.

D - Viosca Knoll 738 & 739

Profile
- 47% average working interest in Viosca Knoll blocks 738 & 739 (Pecten/Maria prospects).
- Located offshore Mississippi in 600' to 900' of water.
- Obtained in 2000 merger.
- 2.2 million barrels of oil equivalent reserves at 12/31/00.

2000 Activity
- Drilled and completed 2 exploratory wells.
- Initiated fabrication and installation of subsea elements.

2001 Plans
- Tie-in 2000 discoveries and initiate production.
- Initiate drilling of additional exploratory wells.

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: 41.0 MMBoe.

F - MT. MASSIVE
- Garden Banks 556, 600 & 601
- Located offshore Louisiana in 3,200' of water.
- Target formation: Pliocene sands at 18,000' to 24,000'.
- 25% working interest.
- Net unrisked reserve potential: 21.0 MMBoe.

G - PALADIN
- Garden Banks 212 & 213
- Located offshore Louisiana in 1,500' of water.
- Target formation: Pliocene sands at 15,000' to 18,000'.
- 33% working interest.
- Net unrisked reserve potential: 21.0 MMBoe.

2001 Plans
- Finalize geophysical analysis.
- Drill exploratory test wells.

GULF - ONSHORE

A - South Texas

Profile
- Up to 100% working interest in 429,000 acres.
- Obtained in 1999 merger.
- 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'.
- 15.7 million barrels of oil equivalent reserves at 12/31/00.

2000 Activity
- Drilled 31 development wells.
- Drilled 3 exploratory wells.
- Acquired additional acreage.

2001 Plans
- Drill 46 development wells.
- Drill 9 exploratory wells.
- Acquire additional acreage.

B - South Louisiana

Profile
- 50% to 100% working interest in 127,000 acres.
- Obtained in 1999 merger.
- Key properties include Lake Arthur South, Patterson Field and Quarantine Bay.
- Produces from the lower, mid and upper Miocene sands at 6,000' to 16,000'.
- 4.8 million barrels of oil equivalent reserves at 12/31/00.

2000 Activity
- Brought previously drilled Patterson well onto production.
- Drilled 1 additional exploratory well.
- Drilled 1 development well.
- Performed 5 workovers.
- Interpreted 3D seismic data.

2001 Plans
- Drill 4 exploitation wells at Quarantine Bay.
- Drill 2 exploratory wells at Patterson Field.

CANADA

A - Peace River Arch

Profile
- 64% average working interest in 550,000 acres in northwestern Alberta.
- Key areas include Hamburg, Chinchaga, Wildmint, Ladyfern and Pouce Coupe.
- Drilling is primarily winter-only access in Hamburg/Chinchaga with year-round access at Pouce Coupe.
- 100% interest in 2 gas processing plants; 60% interest in 1 gas processing plant.
- Produces liquids-rich gas and light oil from multiple formations.
- 13.5 million barrels of oil equivalent reserves at 12/31/00.

2000 Activity
- Drilled and completed 5 of 8 exploratory Slave Point wells.
- Tied in 1999 gas discovery at Chinchaga.
- Acquired 56,000 net acres for Slave Point exploration.
- Drilled and completed 3 shallow Bluesky wells at Chinchaga.
- Drilled and completed 7 of 8 exploratory wells at Pouce Coupe/Buick Creek.
- Acquired 3D seismic data at Hamburg, Chinchaga and Pouce Coupe.

2001 Plans
- Drill 10 exploratory Slave Point wells at Hamburg.
- Drill 9 exploratory wells in the Pouce Coupe/Buick Creek area.
- Conduct 3D seismic surveys to define future Slave Point prospects.

B - Northeastern Plains

Profile
- 75% average working interest in 2.2 million acres in north and central Alberta.
- Key areas include Smoky Bear, Springburn, Cherpeta, Hangingstone, Redsprings, Kirby and Halkirk.
- Includes winter-only drilling areas in northern Alberta.
- Produces shallow gas from multiple formations at 1,000' to 2,500' and oil and gas from 4,000' to 8,000'.
- 53.1 million barrels of oil equivalent reserves at 12/31/00.

2000 Activity
- Drilled and completed 38 of 40 Halkirk wells.
- Drilled and completed 85 of 104 shallow gas wells.
- Drilled and completed 9 oil wells.
- Constructed 3 gas processing facilities.
- Acquired 53,000 net acres at Springburn.
- Completed strategic property acquisition at Goodfish.

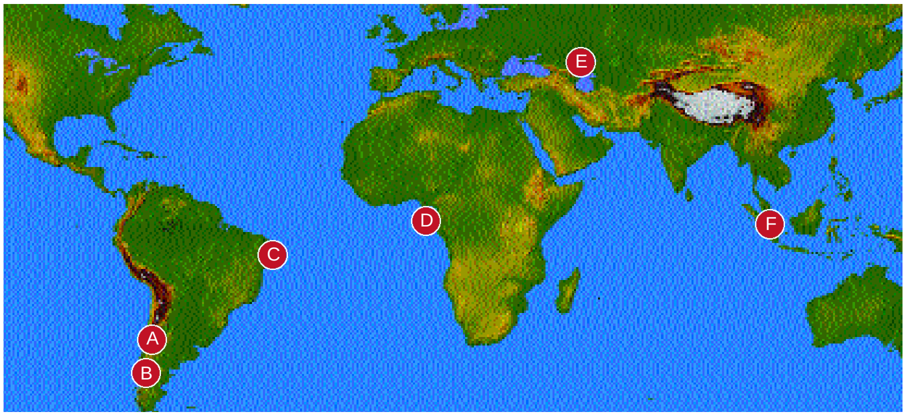
2001 Plans
- Drill 130 shallow gas wells.
- Drill 20 Halkirk oil wells.
- Expand tank battery at Halkirk.
- Expand gas processing facilities.

C - Foothills

Profile
- 47% working interest in 384,000 acres.
- Key areas include exploratory prospects in northeast British Columbia, Narraway and Bighorn in west central Alberta and Coleman in the south.
- 100% interest in 100 million cubic feet per day Coleman gas plant.
- Produces gas from multiple formations at 6,000' to 15,000'.
- 22.2 million barrels of oil equivalent reserves at 12/31/00.

2000 Activity
- Drilled and completed Weejay delineation well.
- Drilled and completed 4 of 5 exploratory wells.
- Initiated drilling of additional exploratory wells.
- Negotiated expansion of existing gas pipeline system to tie-in Weejay gas.
- Acquired 22,000 net acres in the northern foothills.

2001 Plans
- Continue drilling exploratory wells initiated in 2000.
- Drill 7 northern foothills exploratory wells.



INTERNATIONAL

A - Argentina - Neuquen Basin Gas

Profile
- 2 Devon operated blocks include Sierra Chata Field and El Mangrullo Field.
- Obtained in 2000 merger.
- Produces primarily gas.
- 32.5 million barrels of oil equivalent reserves at 12/31/00.

2000 Activity
- Drilled 6 development wells at Sierra Chata.
- Expanded Sierra Chata booster compression.
- Initiated drilling of 2 exploratory wells at Sierra Chata.
- Drilled exploratory well at El Mangrullo.
- Acquired 3D seismic data at El Mangrullo.

2001 Plans
- Continue drilling Sierra Chata exploratory wells initiated in 2000.
- Drill 3 exploratory and 6 development wells at Sierra Chata.
- Drill 4 development wells at El Mangrullo.
- Process and interpret El Mangrullo 3D seismic data.
- Negotiate and secure gas sales contract.

B - Argentina - San Jorge Basin Oil

Profile
- Includes El Tordillo block.
- Obtained in 2000 merger.
- Produces primarily oil from multiple formations at 4,000' to 9,000'.
- 20.0 million barrels of oil equivalent reserves at 12/31/00.

2000 Activity
- Drilled 65 development wells.
- Drilled and completed exploratory well.
- Drilled and completed delineation well.

2001 Plans
- Drill 59 development wells.
- Perform 35 well deepenings and workovers.
- Expand waterflood and upgrade facilities.

C - Offshore Brazil

Profile
- 5 licensed offshore blocks include Carauna, BES-3, BMC-8, BPOT-2 and BSEAL-4.
- 418,000 net acres.
- Obtained in 1999 and 2000 mergers.
- Targeting primarily oil from multiple formations and depths.
- 13.9 million barrels of oil equivalent reserves at 12/31/00.

2000 Activity
- Drilled 2 delineation wells at Carauna.
- Re-entered 2 wells at Carauna to establish production.
- Initiated drilling of exploration well at BES-3.
- Interpreted 3D seismic data.

2001 Plans
- Continue drilling BES-3 well initiated in 2000.
- Drill 1 appraisal well at Carauna.
- Drill 1 exploratory well at BMC-8.
- Drill 2 exploratory wells at BPOT-2.
- Drill 1 exploratory well at BSEAL-4.

D - 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 merger.
- Interest in 6 oil producing wells on the Kowe block.
- 6.7 million barrels of oil equivalent reserves at 12/31/00.

2000 Activity
- Secured farmout agreement with partner to participate in 3 offshore blocks.
- Drilled 2 exploratory dry holes.

2001 Plans
- Spud exploration well in Marine IX block in late 2001 or early 2002.
- Acquire 3D seismic data on Agali block.

E - Azerbaijan

Profile
- 4.8% carried interest in 137,000 acres in the Azeri-Chirag-Gunashli (ACG) oil fields offshore Azerbaijan.
- Obtained in 1999 merger.
- 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.
- 104.2 million barrels of oil equivalent reserves at 12/31/00.

2000 Activity
- Negotiated purchase of additional interest.
- Initiated debottlenecking project to increase production.

2001 Plans
- Finalize purchase of additional 0.8% interest.
- Initiate drilling of 3 extended reach wells on the Chirag 1 platform.
- Finalize plans for next development phase for the Azeri Field.

F - Indonesia - Sumatra Basin

Profile
- 3 licensed blocks on the island of Sumatra include: 30% working interest in Jabung, 50% working interest in Bangko and 30% working interest in South Jambi B.
- Initial position obtained in 2000 merger.
- 43.9 million barrels of oil equivalent reserves at 12/31/00.

2000 Activity
- Performed technical evaluation of Bangko block and identified 2001 exploratory drilling location.
- Drilled 7 development wells in the N. Geragai and Makmur Fields of the Jabung block.
- Also at Jabung, drilled and completed 2 wells and placed 2 existing wells on production at Betara.
- Drilled and completed 1 of 3 exploratory wells.
- Negotiated Singapore gas supply agreements.

2001 Plans
- Drill 3 exploratory and 20 development wells on the Jabung block.
- Drill exploratory well on the Bangko block.
- Drill exploratory well and 2 development wells on the South Jambi B block.

The right

controls.

SELECTED ELEVEN-YEAR FINANCIAL DATA

		1990	1991	1992	1993
OPERATING RESULTS (in thousands, except per share data)					
Revenues (net of royalties):					
Oil sales	$	354,577	351,003	391,945	390,693
Gas sales	$	72,237	73,184	131,028	188,485
Natural gas liquids sales	$	4,699	5,572	8,298	13,101
Other revenue	$	16,625	18,622	13,177	31,418
Total revenues	$	448,138	448,381	544,448	623,697
Production and operating expenses	$	175,422	180,698	215,826	245,218
Depreciation, depletion and amortization of property and equipment	$	88,161	103,364	150,045	174,067
Amortization of goodwill (1)	$	—	—	—	—
General and administrative expenses	$	32,394	37,459	43,072	49,513
Expenses related to prior merger	$	—	—	—	10,800
Interest expense (2)	$	54,256	46,009	56,816	47,207
Deferred effects of change in currency rates on subsidiary's long-term debt	$	—	—	—	—
Reduction of carrying value of oil and gas properties	$	5,900	238,000	66,600	216,000
Income tax expense (benefit)	$	30,628	(51,911)	814	(65,219)
Total expenses	$	386,761	553,619	533,173	677,586
Net earnings (loss) before minority interest, extraordinary item and cumulative effect of change in accounting principle (3)	$	61,377	(105,238)	11,275	(53,889)
Net earnings (loss)	$	61,377	(105,238)	11,275	(55,175)
Preferred stock dividends	$	2,324	2,270	6,003	7,000
Net earnings (loss) to common shareholders	$	59,053	(107,508)	5,272	(62,175)
Net earnings (loss) per common share - basic	$	2.05	(3.66)	0.14	(1.27)
Net earnings (loss) per common share - diluted	$	1.94	(3.66)	0.13	(1.27)
Cash margin (4)	$	167,821	171,312	220,443	270,248
Weighted average shares outstanding - basic		28,785	29,398	38,600	48,808
Weighted average shares outstanding - diluted		30,443	29,398	42,074	48,928
BALANCE SHEET DATA (in thousands)					
Total assets	$	1,075,947	884,675	1,463,814	1,336,411
Debentures exchangeable into shares of Chevron Corporation common stock (5)	$	—	—	—	—
Other long-term debt (6)	$	445,200	472,800	570,857	507,640
Deferred revenues	$	11,200	10,200	13,000	8,600
Deferred income taxes	$	106,677	41,911	51,925	—
Stockholders' equity	$	321,193	203,488	502,783	472,461
Common shares outstanding		29,416	29,522	48,180	49,206

(1) Goodwill of $346.9 million was recognized on Devon's balance sheet as a result of the August 1999 merger with PennzEnergy.
(2) Includes distributions on preferred securities of subsidiary trust of $4,753,000; $9,717,000; $9,717,000; and $6,884,000 in 1996, 1997, 1998 and 1999, respectively.
(3) Before minority interest in Monterrey Resources, Inc. of ($1,300,000) and ($4,700,000) in 1996 and 1997, respectively; extraordinary item of ($6,000,000) and ($4,200,000) in 1996 and 1999, respectively; and the cumulative effect of change in accounting principle of ($1,286,000) in 1993.
(4) Revenues less cash expenses.
(5) Devon beneficially owns approximately 7.1 million shares of Chevron Corporation common stock. These shares have been deposited with an exchange agent for possible exchange for $761.2 million principal amount of exchangeable debentures. The Chevron shares and debentures were acquired through the August 1999 merger with PennzEnergy.
(6) Includes preferred securities of subsidiary trust of $149.5 million in years 1996, 1997 and 1998.
NM Not a meaningful figure.

1994	1995	1996	1997	1998	1999	2000	5-Year Growth Rate	10-Year Growth Rate
393,552	463,868	584,519	555,237	309,990	561,018	**1,078,759**	18%	12%
170,871	162,060	220,556	375,193	347,273	627,869	**1,485,221**	56%	35%
12,705	15,401	28,712	35,838	24,715	67,985	**154,465**	59%	42%
16,453	36,452	36,470	48,255	24,248	20,596	**65,658**	13%	15%
593,581	677,781	870,257	1,014,523	706,226	1,277,468	**2,784,103**	33%	20%
237,997	247,214	296,336	317,588	274,618	377,472	**597,333**	19%	13%
155,392	171,040	192,107	285,708	243,144	406,375	**693,340**	32%	23%
—	—	—	—	—	16,111	**41,332**	NM	NM
44,708	43,006	47,411	53,081	45,454	80,645	**93,008**	17%	11%
7,000	—	—	—	13,149	16,800	**60,373**	NM	NM
32,384	41,285	53,515	51,205	53,249	116,497	**154,329**	30%	11%
—	307	199	5,860	16,104	(13,154)	**2,408**	51%	NM
28,879	97,061	33,100	641,314	422,500	476,100	**—**	NM	NM
32,896	23,361	89,286	(126,742)	(126,107)	(49,434)	**411,638**	78%	30%
539,256	623,274	711,954	1,228,014	942,111	1,427,412	**2,053,761**	27%	18%
54,325	54,507	158,303	(213,491)	(235,885)	(149,944)	**730,342**	68%	28%
54,325	54,507	151,003	(218,191)	(235,885)	(154,144)	**730,342**	68%	28%
11,700	14,800	47,200	12,000	—	3,651	**9,735**	(8%)	15%
42,625	39,707	103,803	(230,191)	(235,885)	(157,795)	**720,607**	79%	28%
0.84	0.76	1.97	(3.35)	(3.32)	(1.68)	**5.66**	49%	11%
0.84	0.76	1.92	(3.35)	(3.32)	(1.68)	**5.50**	49%	11%
275,836	338,984	442,461	556,892	323,469	662,998	**1,748,267**	39%	26%
50,892	52,317	52,744	68,732	70,948	93,653	**127,421**	19%	16%
53,816	52,512	55,553	75,366	76,932	99,313	**131,730**	20%	16%
1,474,953	1,638,710	2,241,890	1,965,386	1,930,537	6,096,360	**6,860,478**	33%	20%
—	—	—	—	—	760,313	**760,313**	NM	NM
457,164	564,537	511,000	576,537	885,371	1,656,208	**1,288,523**	18%	11%
7,400	4,900	4,000	3,700	3,600	104,800	**113,756**	88%	26%
29,618	48,233	136,103	42,525	—	344,593	**626,826**	67%	19%
687,516	739,447	1,159,772	1,006,546	749,763	2,521,320	**3,277,604**	35%	26%
52,160	52,446	62,900	70,770	70,909	126,323	**128,638**	20%	16%

OVERVIEW

On May 25, 2000, Devon and Santa Fe Snyder Corporation (“Santa Fe Snyder”) announced their intent to merge. The transaction was closed on August 29, 2000. The merger was the largest transaction in our history, and it moved us into the top five of U.S.-based independent oil and gas producers. As a result of the transaction, we issued 40.6 million shares of common stock. We also assumed $730.9 million of long-term debt and $492.7 million of other liabilities. The merger increased our proved reserves by 386 MMBoe, or 58%, and our undeveloped leasehold by 16 million acres, or 99%.

The merger with Santa Fe Snyder significantly expanded Devon’s operations. However, another significant event contributing to our growth over the last three years was our 1999 acquisition of PennzEnergy Company (“PennzEnergy”). The acquisition of PennzEnergy added 396 MMBoe of reserves and 13 million net acres of undeveloped leasehold. It also added $3.2 billion of assets to our balance sheet. In exchange, we issued 21.5 million shares of common stock and assumed $1.6 billion of long-term debt and $0.7 billion of other liabilities. The merger was accounted for under the purchase method of accounting for business combinations. Therefore, Devon’s 1999 results do not include any effect of PennzEnergy’s operations prior to August 17, 1999.

On December 10, 1998, Devon and Northstar Energy Corporation (“Northstar”) merged. The combination of Devon and Northstar added 115 million MMBoe of proved reserves and 1.8 million undeveloped acres, all in Canada. The Northstar combination was accounted for under the pooling-of-interests method of accounting for business combinations. Accordingly, our results for 1998 and prior years include the results of both Devon and Northstar as if the two had always been combined.

In addition to the mergers and acquisitions, Devon’s exploration, drilling and development efforts have also been significant contributors to our growth. In 1998 and 1999, before the merger with Santa Fe Snyder, Devon spent approximately $0.5 billion for exploration, drilling and development. These costs included drilling 1,233 wells, of which 1,137 were completed as producers. In 2000, Devon and Santa Fe Snyder combined spent $0.9 billion for exploration, drilling and development efforts. These costs included drilling 1,328 wells, of which 1,261 were completed as producers.

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 combined with those of Santa Fe Snyder for all years presented. Thus, the three-year comparisons of production, revenue and expense items beginning on the following page 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 disguises the substantial changes in Devon’s operations that have occurred as a result of that transaction.

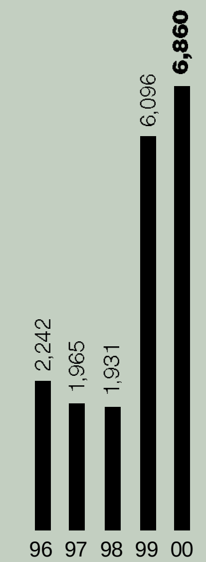
To reflect the positive effects of the Santa Fe Snyder and PennzEnergy transactions and our drilling and development activities during the last three years, the following statistics are presented. This data assumes that our merger with Santa Fe Snyder was closed at the beginning of 2000, and that prior year results were not restated. Thus, it compares Devon’s 2000 results, including Santa Fe Snyder, to those of 1998 for Devon only. The data yield the following notable comparisons:

- **Combined oil, gas and NGL production increased 85.0 million Boe, or 236%.**
- **The average combined price of oil, gas and NGL increased by $11.68 per Boe, or 108%.**
- **Total revenues increased $2.3 billion, or 599%.**
- **Net cash provided by operating activities increased $1.4 billion, or 745%.**
  Cash margin increased $1.6 billion, or 853%.
- **Net earnings increased $790.6 million.**
- **Earnings per share increased to $5.50 per diluted share from a loss of $1.25 per share in 1998.**

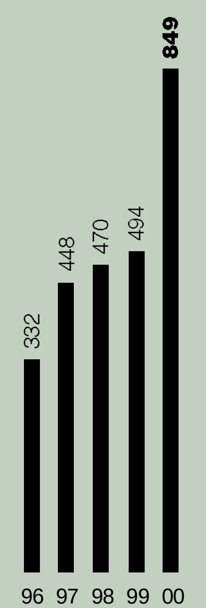
During 2000, we marked our twelfth anniversary as a public company. While Devon has consistently increased production over this twelve-year period, volatility in oil and gas prices has resulted in considerable variability in earnings and cash flows. Prices for oil, natural gas and NGL are determined primarily by market conditions. Market conditions for these products have been, and will continue to be, influenced by regional and world-wide economic growth, weather and other factors that are beyond our control. Devon’s future earnings and cash flows will continue to depend on market conditions.

Because oil and gas prices are influenced by many factors outside our control, Devon’s management has focused its efforts on increasing oil and gas reserves and production and controlling

TOTALASSETS
($ Millions)



CAPITALEXPENDITURES FOR DRILLING AND DEVELOPMENT
($ Millions)



expenses. Over our twelve-year history as a public company, we have been able to significantly reduce our operating costs per unit of production. Future earnings and cash flows are dependent on our ability to continue to contain operating costs at levels that allow for profitable production from our oil and gas properties.

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. Future growth, if any, will depend on our ability to continue to add reserves in excess of production.

RESULTS OF OPERATIONS

Our total revenues have risen from $706.2 million in 1998 to $2.8 billion in 2000. 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 1998 to 2000 are shown in the following tables. (Unless otherwise stated, all dollar amounts are expressed in U.S. dollars.)

TOTAL

YEAR ENDED DECEMBER 31,		2000	2000 vs 1999	1999	1999 vs 1998	1998
			(ABSOLUTE AMOUNTS IN THOUSANDS)			
PRODUCTION						
Oil (MBbls)		42,561	+34%	31,756	+24%	25,628
Gas (MMcf)		426,146	+40%	304,203	+54%	198,051
NGL (MBbls)		7,400	+45%	5,111	+67%	3,054
Oil, gas and NGL (MBoe)		120,985	+38%	87,568	+42%	61,691
REVENUES						
Per Unit of Production:						
Oil (per Bbl)	$	25.35	+43%	17.67	+46%	12.10
Gas (per Mcf)	$	3.49	+69%	2.06	+18%	1.75
NGL (per Bbl)	$	20.87	+57%	13.30	+64%	8.09
Oil, gas and NGL (per Boe)	$	22.47	+57%	14.35	+30%	11.05
Absolute:						
Oil	$	1,078,759	+92%	561,018	+81%	309,990
Gas	$	1,485,221	+137%	627,869	+81%	347,273
NGL	$	154,465	+127%	67,985	+175%	24,715
Oil, gas and NGL	$	2,718,445	+116%	1,256,872	+84%	681,978

DOMESTIC

YEAR ENDED DECEMBER 31,		2000	2000 vs 1999	1999	1999 vs 1998	1998
			(ABSOLUTE AMOUNTS IN THOUSANDS)			
PRODUCTION						
Oil (MBbls)		28,562	+60%	17,822	+45%	12,257
Gas (MMcf)		355,087	+61%	221,061	+82%	121,419
NGL (MBbls)		6,702	+52%	4,396	+78%	2,468
Oil, gas and NGL (MBoe)		94,445	+60%	59,062	+69%	34,962
REVENUES						
Per Unit of Production:						
Oil (per Bbl)	$	25.45	+37%	18.64	+50%	12.43
Gas (per Mcf)	$	3.67	+62%	2.27	+12%	2.02
NGL (per Bbl)	$	20.30	+55%	13.11	+63%	8.05
Oil, gas and NGL (per Boe)	$	22.95	+52%	15.10	+26%	11.94
Absolute:						
Oil	$	726,897	+119%	332,219	+118%	152,297
Gas	$	1,304,626	+160%	501,841	+105%	245,145
NGL	$	136,048	+136%	57,610	+190%	19,871
Oil, gas and NGL	$	2,167,571	+143%	891,670	+114%	417,313

CANADA

YEAR ENDED DECEMBER 31,		2000	2000 vs 1999	1999	1999 vs 1998	1998
			(ABSOLUTE AMOUNTS IN THOUSANDS)			
PRODUCTION						
Oil (MBbls)		4,760	-8%	5,178	-17%	6,257
Gas (MMcf)		62,284	-15%	73,561	+10%	67,158
NGL (MBbls)		682	-3%	700	+24%	566
Oil, gas and NGL (MBoe)		15,823	-13%	18,138	+1%	18,016
REVENUES						
Per Unit of Production:						
Oil (per Bbl)	$	24.46	+58%	15.51	+29%	12.07
Gas (per Mcf)	$	2.71	+75%	1.55	+16%	1.34
NGL (per Bbl)	$	26.51	+84%	14.39	+75%	8.20
Oil, gas and NGL (per Boe)	$	19.18	+70%	11.27	+20%	9.43
Absolute:						
Oil	$	116,427	+45%	80,298	+6%	75,493
Gas	$	169,032	+48%	114,128	+27%	89,828
NGL	$	18,078	+79%	10,075	+117%	4,644
Oil, gas and NGL	$	303,537	+48%	204,501	+20%	169,965

INTERNATIONAL

YEAR ENDED DECEMBER 31,		2000	2000 vs 1999	1999	1999 vs 1998	1998
			(ABSOLUTE AMOUNTS IN THOUSANDS)			
PRODUCTION						
Oil (MBbls)		9,239	+6%	8,756	+23%	7,114
Gas (MMcf)		8,775	-8%	9,581	+1%	9,474
NGL (MBbls)		16	+7%	15	-25%	20
Oil, gas and NGL (MBoe)		10,717	+3%	10,368	+19%	8,713
REVENUES						
Per Unit of Production:						
Oil (per Bbl)	$	25.48	+50%	16.96	+47%	11.55
Gas (per Mcf)	$	1.32	+6%	1.24	-5%	1.30
NGL (per Bbl)	$	21.19	+6%	20.00	+100%	10.00
Oil, gas and NGL (per Boe)	$	23.08	+49%	15.50	+43%	10.87
Absolute:						
Oil	$	235,435	+59%	148,501	+81%	82,200
Gas	$	11,563	-3%	11,900	-3%	12,300
NGL	$	339	+13%	300	+50%	200
Oil, gas and NGL	$	247,337	+54%	160,701	+70%	94,700

OIL REVENUES *2000 vs. 1999* Oil revenues increased $517.7 million in 2000. Oil revenues increased $326.8 million due to a $7.68 per barrel increase in the average price of oil in 2000. An increase in 2000's production of 10.8 million barrels caused oil revenues to increase by $190.9 million. The PennzEnergy merger accounted for 6.8 million barrels of the 10.8 million barrel increase in production. The 2000 period included twelve months of production from the properties acquired in the 1999 PennzEnergy merger. The 1999 period included production from these properties for only 4 1/2 months following the August 17, 1999 merger closing. Additionally, drilling activity and smaller acquisitions, offset in part by property dispositions and natural declines, caused a 4.0 million barrel increase in production.

1999 vs. 1998 Oil revenues increased $251.0 million in 1999. Oil revenues increased $176.9 million due to a $5.57 per barrel increase in the average price of oil in 1999. A 6.1 million barrel increase in 1999's production caused oil revenues to increase by $74.1 million. The August 1999 PennzEnergy merger added 5.3 million barrels of production during the last 4 1/2 months of 1999. The Snyder merger added 1.1 million barrels of production during the last eight months of 1999. These increases were partially offset by a 0.3 million barrel decline in 1999 production from other properties.

GAS REVENUES *2000 vs. 1999* Gas revenues increased $857.4 million in 2000. A 121.9 Bcf increase in production in 2000 added $251.7 million of gas revenues compared to 1999. A $1.43 per Mcf increase in the average gas price in 2000 contributed $605.7 million of the increase in gas revenues. The PennzEnergy merger accounted for 89.3 Bcf of the 121.9 Bcf increase in consolidated production.

All of the 89.3 Bcf added by the PennzEnergy merger was attributable to domestic properties. Production from Devon's other domestic properties increased 44.7 Bcf, due primarily to additional development and acquisitions, net of natural declines and dispositions.

Canadian gas production decreased 11.3 Bcf, or 15%, in 2000. Natural decline, increased royalty rates and dispositions of certain properties were the primary reasons for the production decline. While, domestic royalty rates are fixed percentages, Canadian royalties are based on a sliding scale. As prices increased in 2000, the Canadian government's royalty percentage also increased. This caused Devon's net production to decrease. Gross Canadian gas production, before royalties, was 83.4 Bcf in 2000 compared to 92.1 Bcf in 1999.

1999 vs. 1998 Gas revenues increased $280.6 million in 1999. A 106.2 Bcf increase in production in 1999 added $186.1 million of gas revenues compared to 1998. A $0.31 per Mcf increase in the average gas price in 1999 contributed $94.5 million of the increase in gas revenues. The production increase was primarily related to the PennzEnergy and Snyder mergers. The PennzEnergy properties added 55.5 Bcf of production during the 4 1/2 months following the PennzEnergy merger. The Snyder properties added 36.9 Bcf of production during the last eight months following the May 1999 Snyder merger. A 6.4 Bcf increase in Devon's Canadian gas production also contributed to the increase in 1999 gas production.

NGL REVENUES *2000 vs. 1999* NGL revenues increased $86.5 million in 2000. An increase in 2000's average price of $7.57 per barrel caused NGL revenues to increase $56.0 million. A production increase of 2.3 million barrels in 2000 caused revenues to increase $30.5 million. The 1999 PennzEnergy merger accounted for 2.5 million barrels of increased NGLproduction in 2000. This increase was partially offset by a 0.2 million barrel reduction in 2000 production from Devon's other properties. This reduction was caused by property dispositions and natural decline, offset in part by drilling activity and property acquisitions.

1999 vs. 1998 NGL revenues increased $43.3 million in 1999. An increase in 1999's average price of $5.21 per barrel caused NGL revenues to increase $26.6 million. A production increase of 2.1 million barrels in 1999 caused revenues to increase $16.7 million. Production from the PennzEnergy properties for the last 4 1/2 months of 1999 accounted for 1.7 million barrels of the 1999 increase.

OTHER REVENUES *2000 vs. 1999* Other revenues increased $45.1 million, or 219% in 2000. Increases in third party gas processing income and interest income were the primary reasons. Additionally, the 2000 period included $18.4 million of dividend income. This resulted from 7.1 million shares of Chevron Corporation common stock acquired by Devon in the 1999 PennzEnergy merger. The 1999 period included $6.7 million of dividend income on these same shares.

1999 vs. 1998 Other revenues decreased $3.7 million in 1999. Other revenues in 1998 included $8.8 million of one-time revenues recognized by Northstar in 1998 from terminations of certain management agreements and gas contracts. Other revenues in 1998 also included $4.7 million of interest income from federal income tax audits recognized by Santa Fe Snyder. In comparing 1999 to 1998, these nonrecurring 1998 revenues more than offset increases of $9.8 million in 1999 from other sources of revenues. These other sources included dividend income, interest income and third-party gas processing revenues. Other revenues in 1999 included $6.7 million of dividend income in the last 4 1/2 months of the year from the shares of Chevron Corporation common stock.

EXPENSES The details of the changes in pre-tax expenses between 1998 and 2000 are shown in the table below.

YEAR ENDED DECEMBER 31,	2000	2000 vs 1999	1999	1999 vs 1998	1998
		(ABSOLUTE AMOUNTS IN THOUSANDS)			
Absolute:					
Production and operating expenses:					
Lease operating expenses	$ **440,780**	+48%	298,807	+32%	226,561
Transportation costs	**53,309**	+57%	33,925	+46%	23,186
Production taxes	**103,244**	+131%	44,740	+80%	24,871
Depreciation, depletion and amortization of oil and gas properties	**662,890**	+70%	390,117	+69%	230,419
Amortization of goodwill	**41,332**	+157%	16,111	N/M	—
Subtotal	**1,301,555**	+66%	783,700	+55%	505,037
Depreciation and amortization of non-oil and gas properties	**30,450**	+87%	16,258	+28%	12,725
General and administrative expenses	**93,008**	+15%	80,645	+77%	45,454
Expenses related to mergers	**60,373**	+259%	16,800	+28%	13,149
Interest expense	**154,329**	+41%	109,613	+152%	43,532
Deferred effect of changes in foreign currency exchange rate on subsidiary’s long-term debt	**2,408**	N/M	(13,154)	N/M	16,104
Distributions on preferred securities of subsidiary trust	**—**	-100%	6,884	-29%	9,717
Reduction of carrying value of oil and gas properties	**—**	-100%	476,100	+13%	422,500
Total	$ **1,642,123**	+11%	1,476,846	+38%	1,068,218
Per Boe:					
Production and operating expenses:					
Lease operating expenses	$ **3.65**	+7%	3.41	-7%	3.67
Transportation costs	**0.44**	+13%	0.39	+3%	0.38
Production taxes	**0.85**	+67%	0.51	+28%	0.40
Depreciation, depletion and amortization of oil and gas properties	**5.48**	+23%	4.46	+19%	3.74
Amortization of goodwill	**0.34**	+89%	0.18	N/M	—
Subtotal	**10.76**	+20%	8.95	+9%	8.19
Depreciation and amortization of non-oil and gas properties (1)	**0.25**	+32%	0.19	-10%	0.21
General and administrative expenses (1)	**0.77**	-16%	0.92	+24%	0.74
Expenses related to prior mergers(1)	**0.50**	+163%	0.19	-10%	0.21
Interest expense (1)	**1.27**	+2%	1.25	+79%	0.70
Deferred effect of changes in foreign currency exchange rate on subsidiary’s long-term debt (1)	**0.02**	N/M	(0.15)	N/M	0.26
Distributions on preferred securities of subsidiary trust (1)	**—**	-100%	0.08	-50%	0.16
Reduction of carrying value of oil and gas properties (1)	**—**	-100%	5.44	-21%	6.85
Total	$ **13.57**	-20%	16.87	-3%	17.32

(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.
N/M - Not meaningful.

PRODUCTION AND OPERATING EXPENSES The details of the changes in production and operating expenses between 1998 and 2000 are shown in the table below.

TOTAL YEAR ENDED DECEMBER 31,		2000	2000 vs 1999	1999	1999 vs 1998	1998
			(ABSOLUTE AMOUNTS IN THOUSANDS)			
Absolute:						
Recurring lease operating expenses	$	**422,853**	+45%	291,037	+33%	219,316
Well workover expenses		**17,927**	+131%	7,770	+7%	7,245
Transportation costs		**53,309**	+57%	33,925	+46%	23,186
Production taxes		**103,244**	+131%	44,740	+80%	24,871
Total production and operating expenses	$	**597,333**	+58%	377,472	+37%	274,618
Per Boe						
Recurring lease operating expenses	$	**3.50**	+5%	3.32	-7%	3.56
Well workover expenses		**0.15**	+67%	0.09	-18%	0.11
Transportation costs		**0.44**	+13%	0.39	+3%	0.38
Production taxes		**0.85**	+67%	0.51	+28%	0.40
Total production and operating expenses	$	**4.94**	+15%	4.31	-3%	4.45

2000 vs. 1999 Recurring lease operating expenses increased $131.8 million, or 45%, in 2000. The 1999 PennzEnergy merger accounted for $92.4 million of the increase in expenses. Additionally, $11.0 million of costs were added by the August 1999 and January 2000 acquisitions of certain properties and $7.7 million of costs were added by the Snyder merger. Other than the added costs from these acquisitions, Devon's recurring costs increased $20.7 million in 2000. This increase was primarily caused by increased production and higher ad valorem taxes and fuel costs.

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 $19.4 million, or 57% in 2000 primarily due to increased production.

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 143% increase in domestic oil, gas and NGL revenues was the primary cause of a 136% increase in domestic production taxes. Production taxes did not increase proportionately to the increase in revenues. This was primarily due to the addition in 1999 of oil and gas revenues from offshore Gulf of Mexico properties acquired in the PennzEnergy merger. Revenues generated from federal offshore properties do not incur state production taxes.

1999 vs. 1998 Recurring lease operating expenses increased $71.7 million, or 33%, in 1999. The PennzEnergy properties added $57.3 million of expenses in the last 4 1/2 months of the year. The Snyder properties added $17.7 million of expenses for the last eight months of the year. Other than the added costs from the PennzEnergy and Snyder properties, recurring expenses on Devon's other properties dropped $3.3 million in 1999. Efficiencies achieved in certain of Devon's oil producing properties contributed a substantial portion of this cost reduction.

Transportation costs increased $10.7 million, or 46%, in 1999. This was primarily due to increased production.

As previously stated, most of the U.S. production taxes are based on a fixed percentage of revenues. Therefore, the 114% increase in domestic oil, gas and NGL revenues was the primary cause of a 88% 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 net capitalized investment in those reserves including estimated future development costs (the "depletable base"). Generally, if reserve volumes are revised up or down, then the DD&Arate 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&Arate 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&Ais calculated separately on a country-by-country basis.

2000 vs. 1999 Oil and gas property related DD&Aincreased $272.8 million, or 70%, in 2000. A 38%, increase in total oil, gas and NGL production caused $148.9 million of the increase in DD&A expense. The remaining $123.9 million of oil and gas property related DD&Aexpense increase resulted from a rate increase. Devon's 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 $14.2 million in 2000 compared to 1999. Depreciation of non-oil and gas properties acquired in the PennzEnergy and Snyder mergers and of our new gas pipeline and gathering system in Wyoming accounted for the increase.

1999 vs. 1998 Oil and gas property related DD&Aincreased $159.7 million, or 69%, in 1999. Oil and gas property related DD&A increased $96.7 million due to the 42% increase in oil, gas and NGLproduction in 1999. Oil and gas property related DD&A increased $63.0 million due to an increase in the consolidated DD&Arate. The consolidated DD&A rate increased from $3.74 per Boe in 1998 to $4.46 per Boe in 1999. The 1999 rate of $4.46 per Boe was a blended rate of before and after the PennzEnergy and Snyder mergers.

Non-oil and gas property DD&A increased $3.5 million in 1999 compared to 1998. Depreciation of non-oil and gas properties acquired in the PennzEnergy and Snyder mergers and of the Wyoming gas pipeline and gathering system accounted for the increase in 1999's expense.

AMORTIZATION OF GOODWILL In connection with the PennzEnergy merger, we recorded $346.9 million of goodwill. The goodwill was allocated $299.5 million to domestic operations and $47.4 million to international operations. The goodwill is being amortized using the units-of-production method. Substantially all of the $41.3 million and $16.1 million of amortization recognized in 2000 and 1999, respectively, was related to the domestic balance.

GENERALAND ADMINISTRATIVE EXPENSES ("G&A") Our net G&Aconsists 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&Aitems. 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&Areimbursed by working interest owners of properties for which Devon serves as the operator. These reimbursements are received during both the drilling and operational stages of a property's life. The gross amount of G&A incurred, less the amounts capitalized and reimbursed, is recorded as net G&Ain the consolidated statements of operations. See the following table for a summary of G&Aexpenses by component.

TOTAL YEAR ENDED DECEMBER 31,		2000	2000 vs 1999	1999	1999 vs 1998	1998
				(IN THOUSANDS)		
Gross G&A	$	205,693	+37%	150,441	+57%	95,589
Capitalized G&A		(61,764)	+114%	(28,878)	+95%	(14,812)
Reimbursed G&A		(50,921)	+24%	(40,918)	+16%	(35,323)
Net G&A	$	93,008	+15%	80,645	+77%	45,454

2000 vs. 1999 Net G&A increased $12.4 million in 2000. Gross G&Aincreased $55.3 million in 2000 compared to 1999. The increase in gross expenses was primarily related to additional costs incurred as a result of the 1999 PennzEnergy and Snyder mergers. G&A was reduced $32.9 million in 2000 due to an increase in the amount capitalized as part of oil and gas properties. G&A was also reduced $10.0 million in 2000 by an increase in the amount of reimbursements on operated properties. The increase in capitalized and reimbursed G&Awas primarily related to the 1999 PennzEnergy and Snyder mergers.

1999 vs. 1998 Net G&A increased $35.2 million in 1999. Gross G&Aincreased $54.9 million in 1999. Included in the increase in gross expenses were $36.7 million of expenses related to 4 1/2 months of the PennzEnergy operations. G&A was lowered $14.1 million due to an increase in the amount capitalized as part of oil and gas properties. The 1999 amount capitalized included $5.5 million related to the PennzEnergy operations for the last 4 1/2 months of the year. G&A was also reduced by a $5.6 million increase in the amount of reimbursements on operated properties. The 1999 reimbursements received from the PennzEnergy properties were $6.0 million.

EXPENSES RELATED TO MERGERS Approximately $60.4 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 $16.8 million of expenses were incurred by Santa Fe Snyder in 1999 related to the Snyder merger. These costs included $14.4 million related to compensation plans and other benefits, and $1.9 million of severance and relocation costs. The $16.8 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. Therefore, the costs were required to be expensed as opposed to capitalized as part of the Snyder merger.

Approximately $13.1 million of expenses were incurred in 1998 in connection with the Northstar combination. These expenses consisted primarily of investment bankers'fees, legal fees and costs of printing and distributing the proxy statement to shareholders.

INTEREST EXPENSE *2000 vs. 1999* Interest expense increased $44.7 million, or 41%, in 2000. An increase in the average debt balance outstanding from $1.5 billion in 1999 to $2.3 billion in 2000 caused interest expense to increase by $53.7 million. The increase in average debt outstanding in 2000 was attributable to the long-term debt assumed in the Snyder and PennzEnergy mergers. The average interest rate on outstanding debt decreased from 7.0% in 1999 to 6.7% in 2000. This rate decrease caused interest expense to decrease $4.7 million in 2000. Other items are included in interest expense that are not related to the debt balance outstanding. These items, such as facility and agency fees, amortization of costs and other miscellaneous items, were $4.3 million lower in 2000 compared to 1999.

1999 vs. 1998 Interest expense increased $66.1 million in 1999. An increase in the average debt balance outstanding from $588.3 million in 1998 to $1.5 billion in 1999 caused interest expense to increase by $69.9 million. The increase in average debt outstanding in 1999 was attributable to the long-term debt assumed in the Snyder and PennzEnergy mergers. The average interest rate on outstanding debt decreased from 7.3% in 1998 to 7.0% in 1999. This rate decrease caused interest expense to decrease $4.9 million in 1999. Other items are included in interest expense that are not related to the debt balance outstanding. These items, such as facility and agency fees, amortization of costs and other miscellaneous items, were $1.1 million higher in 1999 compared to 1998.

DEFERRED EFFECT OF CHANGES IN FOREIGN CURRENCY EXCHANGE RATE ON SUBSIDIARY'S LONG-TERM DEBT *2000 vs. 1999* Until mid-January 2000, Devon's Canadian subsidiary, Northstar, had certain fixed-rate senior notes which were denominated in U.S. dollars. Changes in the exchange rate between the U.S. dollar and the Canadian dollar while the notes were outstanding increased or decreased the expected amount of Canadian dollars eventually required to repay the notes. Such changes in the Canadian dollar equivalent balance of the debt were required to be included in determining net earnings for the period in which the exchange rate changed. In mid-January 2000, the U.S. dollar denominated 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, $2.4 million of expense was recognized in 2000.

1999 vs. 1998 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 debt reduced the Canadian dollar equivalent of debt recorded by Northstar at the end of 1999. Therefore, a $13.2 million reduction to expenses was recorded in 1999.

DISTRIBUTIONS ON PREFERRED SECURITIES OF SUBSIDIARY TRUST As discussed in Note 9 to the consolidated financial statements, Devon, through its affiliate Devon Financing Trust, completed the issuance of $149.5 million of 6.5% Trust Convertible Preferred Securities ("TCP Securities") in July 1996. The TCP Securities had a maturity date of June 15, 2026. However, in October 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 of the 2.99 million units of TCP Securities were exchanged for shares of Devon common stock. Accordingly, we issued 4.9 million shares of common stock for substantially all of the outstanding units of TCP Securities. The redemption price for the 950 units redeemed was approximately $50,000.

2000 vs. 1999 There were no TCP Securities distributions in 2000 compared to $6.9 million in 1999. Substantially all of the TCP Securities were exchanged for shares of Devon common stock on November 30, 1999.

1999 vs. 1998 The TCP Securities distributions in 1999 were $6.9 million compared to $9.7 million in 1998. Substantially all of the TCP Securities were exchanged for shares of Devon common stock on November 30, 1999. Therefore, there was no fourth quarter 1999 distribution on the exchanged TCPSecurities.

REDUCTION OF CARRYING VALUE OF OILAND 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. 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 deferred taxes, is written off as an expense.

We did not reduce the carrying value of our oil and gas properties in 2000. During 1999 and 1998, we reduced the carrying value of our oil and gas properties by $476.1 million and $422.5 million, respectively, due to the full-cost ceiling limitations. The after-tax effect of these reductions in 1999 and 1998 were $309.7 million and $280.8 million, respectively.

INCOME TAXES *2000 vs. 1999* Our 2000 financial tax expense rate was 36% of income before income tax expense. This rate was higher than the statutory federal tax rate of 35%. This was due to the effect of goodwill amortization that is not deductible for income tax purposes and the effect of foreign income taxes. The higher rate was offset in part by the recognition of a benefit from the disposition of Devon’s assets in Venezuela. The 1999 financial tax benefit rate was 25%. This rate was lower than the statutory federal tax rate of 35%. This was due to the effect of goodwill amortization that is not deductible for income tax purposes and the effect of foreign income taxes.

1999 vs. 1998 Devon’s 1999 financial tax benefit rate was 25% of loss before income tax benefit. This rate was lower than the statutory federal tax rate of 35% due to the effect of goodwill amortization that is not deductible for income tax purposes and the effect of foreign income taxes. The 1998 financial tax benefit rate was 35%.

CAPITAL EXPENDITURES, CAPITAL RESOURCES AND LIQUIDITY

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

CAPITAL EXPENDITURES Approximately $1.3 billion was spent in 2000 for capital expenditures. This amount included $1.2 billion related to the acquisition, drilling or development of oil and gas properties. These amounts compare to 1999 total expenditures of $883.4 million, $784.9 million of which was related to oil and gas properties. In 1998, total expenditures were $712.8 million, $704.6 million of which was related to oil and gas properties.

OTHER CASH USES Devon’s common stock dividends were $22.2 million, $12.7 million and $7.3 million in 2000, 1999 and 1998, respectively. We also paid $9.7 million of preferred stock dividends in 2000 and $3.7 million in the last 4 1/2 months of 1999 following the PennzEnergy merger.

CAPITAL RESOURCES AND LIQUIDITY Net cash provided by operating activities (“operating cash flow”) has historically been the primary source of Devon’s capital and short-term liquidity. Operating cash flow was $1.6 billion, $532.3 million and $334.5 million in 2000, 1999 and 1998, respectively. The trends in operating cash flow during these periods have generally followed those of the various revenue and expense items previously discussed.

In addition to operating cash flow, our credit lines and the private placement of long-term debt have been an important source of capital and liquidity. In 2000 and 1999, debt repayments exceeded borrowings by $371.6 million and $144.7 million, respectively. During 1998, long-term debt borrowings exceeded repayments by $264.2 million.

Prior to the August 2000 merger, Devon and Santa Fe Snyder each had their own unsecured credit facilities. Devon’s credit facilities prior to the merger aggregated $750 million, with $475 million in a U.S. facility and $275 million in a Canadian facility. These Devon credit facilities were entered into in October 1999. Santa Fe Snyder’s credit facilities prior to the merger aggregated $600 million.

Concurrent with the closing of the Santa Fe Snyder merger on August 29, 2000, Devon entered into new unsecured long-term credit facilities aggregating $1 billion (the “Credit Facilities”). The Credit Facilities replaced the prior separate facilities of Devon and Santa Fe Snyder. 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. We may borrow funds under the Tranche B facility until August 28, 2001 (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. As of December 31, 2000, we had no borrowings under the U.S. Facility.

We may borrow funds under the $275 million Canadian Facility until August 28, 2001 (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. This requires 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. As of December 31, 2000, we had $146.7 million borrowed under the Canadian Facility at a weighted average interest rate of 6.1%.

Amounts borrowed under the Credit Facilities bear interest at various fixed rate options that we may elect for periods up to six months. Such rates are generally less than the prime rate, and are tied to margins determined by our 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.

On August 29, 2000, we entered into a commercial paper program. Total borrowings under the U.S. credit 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 will be 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, 2000, we had no borrowings under the commercial paper program.

In June 2000, Devon privately sold zero coupon convertible senior debentures. The convertible debentures were sold at a price of $464.13 per debenture. This resulted in 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. We may call the debentures at any time after five years, and a debenture holder has the right to require us to repurchase the debentures after 5, 10 and 15 years. Repurchases would be at the issue price plus accrued original issue discount and interest. The proceeds to Devon were approximately $346.1 million, net of debt issuance costs of approximately $6.6 million. We used the proceeds from the sale of these convertible debentures to pay down other domestic long-term debt.

Another significant source of liquidity in 1999 was the $402 million received from the sale of approximately 10.3 million shares of Devon’s common stock in a public offering. The proceeds were primarily used to retire $350 million of long-term debt in the fourth quarter of 1999. The retired debt, which we assumed in the PennzEnergy merger, had an average interest rate of 10% per year. Also, Santa Fe Snyder raised $108 million in 1999 from an equity offering of its common stock following its merger with Snyder.

2001 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, 2000 reserve reports of independent petroleum engineers 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, the 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. 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 NGL are determined primarily by prevailing market conditions. Market conditions for these products are influenced by regional and world-wide 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 NGL. Over 97% of our revenues are attributable to sales of these three commodities. Consequently, Devon’s financial results and resources are highly influenced by this price volatility.

Estimates for Devon’s future production of oil, natural gas and NGL 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 NGLis 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, our net production and proved reserves in such areas could be reduced.

The production, transportation and marketing of oil, natural gas and NGL 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 NGLduring 2001 will be substantially similar to those of 2000, unless otherwise noted. Given the general limitations expressed herein, Devon's forward-looking statements for 2001 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 $0.6695 U.S. dollar to $1.00 Canadian dollar. The actual 2001 exchange rate may vary materially from this estimated rate. Such variations could have a material effect on the following Canadian estimates.

GEOGRAPHIC REPORTING AREAS FOR 2001 The following estimates of production, average price differentials and capital expenditures are provided separately for each of Devon's geographic divisions. These divisions are as follows:

- the Gulf Division, which operates oil and gas properties located primarily in the onshore South Texas and South Louisiana areas and offshore in the Gulf of Mexico;
- the Rocky Mountain Division, which operates oil and gas properties located in the Rocky Mountains area of the United States stretching from the Canadian border south into northern New Mexico;
- the Permian/Mid-Continent Division, which operates all properties located in the United States other than those operated by the Gulf Division and the Rocky Mountain Division;
- Canada; and
- International Division, which encompasses all oil and gas properties that lie outside of the United States and Canada.

YEAR 2001 POTENTIAL OPERATING ITEMS

OIL, GAS AND NGL PRODUCTION Set forth in the following paragraphs are individual estimates of Devon's oil, gas and NGL production in 2001. On a combined basis, Devon estimates its 2001 oil, gas and NGL production will total between 120.4 million and 128.0 million barrels of oil equivalent. Devon's estimates of 2001 production do not include certain oil, gas and NGL production from various properties that were sold during 2000. These sold properties produced approximately 2.9 million barrels of oil equivalent in 2000 that will not be produced by Devon in 2001.

OIL PRODUCTION Devon expects its oil production in 2001 to total between 40.3 million barrels and 42.8 million barrels. The expected ranges of production by division are as follows:

Expected Range of Production (MMBbls)

Permian/Mid-Continent	12.2	to	12.9
Gulf	10.1	to	10.8
Rocky Mountain	3.0	to	3.2
Canadian	5.3	to	5.6
International	9.7	to	10.3

Oil Prices - Fixed We have fixed the price we will receive in 2001 on a portion of our oil production through certain forward oil sales. Devon has executed forward oil sales attributable to the Permian/Mid-Continent Division for 3.7 million barrels at an average price of $16.84 per barrel. These fixed-price volumes represent 9% of our expected consolidated oil production in 2001. Santa Fe Snyder Corporation entered into these forward oil sales agreements in late 1999 and early 2000, and used the proceeds to acquire interests in producing properties in the Gulf of Mexico.

Oil Prices - Floating For the oil production for which prices have not been fixed, Devon's 2001 average prices for each of its divisions are expected to differ from the New York Mercantile Exchange price ("NYMEX") as set forth in the following table. The NYMEX price is the monthly average of settled prices on each trading day for West Texas Intermediate Crude oil delivered at Cushing, Oklahoma.

Expected Range of Oil Prices
Greater Than (Less Than) NYMEX

Permian/Mid-Continent	($3.10) to ($2.10)
Gulf	($2.90) to ($1.90)
Rocky Mountain	($2.50) to ($1.50)
Canadian	($5.50) to ($4.50)
International	($3.65) to ($2.65)

The above range of expected Canadian differentials compared to NYMEX includes an estimated $0.11 per barrel decrease resulting from foreign currency hedges. These hedges, in which Devon will sell $10 million in 2001 at an average Canadian-to-U.S. exchange rate of $0.7102 and buy the same amount of dollars at the floating exchange rate, offset a portion of the exposure to currency fluctuations on those Canadian oil sales that are based on U.S. prices. The $0.11 per barrel decrease is based on the assumption that the average Canadian-to-U.S. conversion rate for the year 2001 is $0.6695.

GAS PRODUCTION Devon expects its 2001 gas production to total between 439 Bcf and 469 Bcf. The expected ranges of production by division are as follows:

Expected Range of Production (Bcf)

Permian/Mid-Continent	114 to 121
Gulf	144 to 153
Rocky Mountain	115 to 123
Canadian	58 to 62
International	8 to 10

Gas Prices - Fixed Through various price swaps and fixed-price physical delivery contracts, we have fixed the price we will receive in 2001 on a portion of our natural gas production. The following tables include information on this fixed-price production by division. 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.

	First Half of 2001		Second Half of 2001	
Division	**Mcf/Day**	**Price/Mcf**	**Mcf/Day**	**Price/Mcf**
Rocky Mountain	20,661	$ 1.90	57,955	$ 3.68
Gulf	-	$ -	40,000	$ 5.45
Canada	60,011	$ 1.53	56,888	$ 1.52

Additionally, Devon has entered into a basis swap on 7.3 Bcf of 2001 gas production. Under the terms of the basis swap, the counterparty pays Devon the average NYMEX price for the last three trading days of each month, less $0.30 per Mcf. In return, Devon pays the counterparty the Colorado Interstate Gas Co. (“CIG”) index price published by “Inside F.E.R.C.’s Gas Market Report” (“Inside FERC”). The effect of this swap is included in Rocky Mountain Division gas revenues. This basis swap does not qualify as a hedge under the provisions of SFAS No. 133. Accordingly, fluctuations in the fair value of this basis swap will be recorded in earnings beginning in the first quarter of 2001.

Gas Prices - Floating For the natural gas production for which prices have not been fixed, Devon’s 2001 average prices for each of its divisions are expected to differ from NYMEX as set forth in the following table. NYMEX 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

Permian/Mid-Continent	($0.40) to $0.10
Gulf	($0.15) to $0.35
Rocky Mountain	($0.90) to ($0.40)
Canadian	($0.85) to ($0.35)
International	($2.60) to ($2.10)

We have also entered into a costless price collar that sets a floor and ceiling price for 20,000 MMBtu/day of Rocky Mountain Division gas production during the second half of 2001. The collar has a floor and ceiling price per MMBtu of $4.10 and $8.00, respectively. The floor and ceiling prices are based on the first-of-the-month CIG price index as published monthly by Inside FERC. If the CIG index is outside of the ranges set by the floor and ceiling prices, Devon and the counterparty to the collar will settle the difference. Any such settlements will either increase or decrease Devon's gas revenues for the period. Because our gas volumes are often sold at prices that differ from related regional indices, and due to differing Btu content of gas production, the floor and ceiling prices of the collar do not reflect actual limits of Devon's realized prices for the production volumes related to the collar.

NGL PRODUCTION We expect our 2001 production of NGL to total between 6.6 million barrels and 7.3 million barrels. The expected ranges of production by division are as follows:

Expected Range of Production (MMBbls)

Permian/Mid-Continent	4.3 to 4.6
Gulf	1.0 to 1.1
Rocky Mountain	0.6 to 0.7
Canadian	0.5 to 0.6
International	0.2 to 0.3

OTHER REVENUES Devon's other revenues in 2001 are expected to be between $53 million and $59 million. This estimated range does not include the gain or loss that could be recognized from changes in the fair values of Devon's derivatives that are not hedges. Substantially all of Devon's derivatives are hedges, but the gas price basis swap previously discussed and the option embedded in the debentures that are exchangeable into shares of Chevron Corporation common stock are not hedges. Accordingly, the changes in the fair value of these derivatives will be recognized in Devon's operating results in 2001.

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.

These factors, coupled with uncertainty of future oil, natural gas and NGL prices, increase the uncertainty inherent in estimating future production and operating costs. Given these uncertainties, Devon estimates that year 2001 lease operating expenses will be between $463 million and $492 million, transportation costs will be between $62 million and $66 million and production taxes will be between 4% and 5% of consolidated oil, natural gas and NGL revenues.

DEPRECIATION, DEPLETION AND AMORTIZATION ("DD&A") The 2001 oil and gas property DD&Arate will depend on various factors. Most notable among such factors are the amount of proved reserves that will be added from drilling or acquisition efforts in 2001 compared to the costs incurred for such efforts. Another factor is revisions to our year-end 2000 reserve estimates that, based on prior experience, are likely to be made during 2001.

In addition to oil and gas property related DD&A, we expect 2001 DD&A expense related to non-oil and gas property fixed assets to total between $30 million and $32 million. Based on this range, and the production estimates discussed earlier, we expect our consolidated DD&A rate to total between $6.15 and $6.45 per Boe.

Devon also expects to record goodwill amortization in 2001. This amortization is expected to be between $33 million and $35 million. The goodwill was recorded in connection with the 1999 merger with PennzEnergy.

GENERALAND ADMINISTRATIVE EXPENSES ("G&A") G&Aincludes the costs of many different goods and services used in support of our business. These goods and services are subject to general price level increases or decreases. In addition, our G&A varies with our level of activity, related staffing needs and the amount of professional services required during any given period. Should 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&Ain 2001 is expected to be between $89 million and $98 million.

INTEREST EXPENSE Future interest rates and oil, natural gas and NGLprices have a significant effect on Devon’s interest expense. Approximately $1.9 billion of our December 31, 2000, long-term debt balance of $2.0 billion bears interest at fixed rates. Such fixed rates remove the uncertainty of future interest rates from some, but not all, of our long-term debt. Also, we can only marginally influence the prices we will receive in 2001 from sales of oil, natural gas and NGLand the resulting cash flow. 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 our control. Given the uncertainty of future interest rates and commodity prices, and assuming that the fixed-rate debt remains in place throughout the year, we estimate that consolidated interest expense in 2001 will be between $143 million and $146 million. Included in this estimate is $12 million of discount accretion on the debentures that are exchangeable into shares of Chevron Corporation common stock. The discount accretion is the result of the adoption of SFAS 133 effective January 1, 2001.

REDUCTION OF CARRYING VALUE OF OILAND GAS PROPERTIES As of December 31, 2000, Devon does not expect to record a reduction in 2001 of its carrying value of oil and natural gas properties under the full-cost accounting ceiling test. At this time the ceiling for each full-cost pool exceeds Devon’s carrying value of oil and natural gas properties, less deferred income taxes. However, such excess could be eliminated by declines in oil and/or natural gas prices between now and the end of any quarter during 2001 or in subsequent periods.

INCOME TAXES We expect our consolidated financial income tax rate in 2001 to be between 35% and 45%. The current income tax rate is expected to be between 20% and 25%. The deferred income tax rate is expected to be between 15% and 20%. There are certain items that will have a fixed impact on 2001’s income tax expense regardless of the level of pre-tax earnings that are produced. These items include Section 29 tax credits in the U.S. These credits reduce income taxes based on production levels of certain properties and are not necessarily affected by pre-tax financial earnings. The amount of Section 29 tax credits expected to be generated to offset financial income tax expense in 2001 is approximately $20 million. Also, Devon’s Canadian subsidiaries are subject to Canada’s “large corporation tax” of approximately $3 million. This tax is based on total capitalization levels, not pre-tax earnings. The financial income tax in 2000 will also be increased by approximately $14 million due to the financial amortization of certain costs, such as goodwill amortization, that are not deductible for income tax purposes. Significant changes in estimated production levels of oil, gas and NGL, the prices of such products, or any of the various expense items could materially alter the effect of the aforementioned items on 2001’s financial income tax rates.

YEAR 2001 POTENTIAL CAPITAL SOURCES, USES AND LIQUIDITY

CAPITAL EXPENDITURES Though we have completed several major property acquisitions in recent years, these transactions are opportunity driven. Thus, we do not “budget,” nor can we reasonably predict, the timing or size of such possible acquisitions, if any.

Our capital expenditures budget is based on an expected range of future oil, natural gas and NGLprices as well as the expected costs of the capital additions. Should price expectations for our future production change significantly, some projects may be accelerated or deferred and, consequently, may increase or decrease total 2001 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 our estimates.

Given the limitations discussed, the company expects its 2001 capital expenditures for drilling and development efforts plus related facilities to total between $1.05 billion and $1.15 billion. These amounts include between $160 million and $180 million for drilling and facilities costs related to reserves classified as proved as of year-end 2000. In addition, these amounts include between $520 million and $560 million for other low risk/reward projects and between $370 million and $410 million for new, higher risk/reward projects. The following table shows expected drilling and facilities expenditures by major operating division.

Drilling and Production Facilities Expenditures (millions)	Rocky Mountain Division	Permian/ Mid-Continent Division	Gulf Division	Canada	Other International
Related to Proved Reserves	$45-$55	$70-$80	$0-$10	$10-$20	$20-$30
Lower Risk/Reward Projects	$45-$55	$90-$100	$185-$215	$40-$50	$140-$170
Higher Risk/Reward Projects	$20-$30	$40-$50	$110-$130	$105-$125	$80-$100
Total	**$110-$140**	**$200-$230**	**$295-$355**	**$155-$195**	**$240-$300**

In addition to the above expenditures for drilling and development, Devon is participating through a joint venture in the construction of gas transportation and processing systems in the Powder River Basin of Wyoming. We expect to spend from $15 million to $20 million as our share of the project in 2001. We also expect to capitalize between $70 million and $80 million of G&A expenses in accordance with the full-cost method of accounting. In addition, we expect to pay between $15 million and $20 million for plugging and abandonment charges in 2001. Finally, we expect to spend between $15 million and $20 million for non-oil and gas property fixed assets.

OTHER CASH USES Devon's management expects the policy of paying a quarterly common stock dividend to continue. With the current $0.05 per share quarterly dividend rate and 129 million shares of common stock outstanding, 2001 dividends are expected to approximate $26 million. In addition, we have $150 million of 6.49% cumulative preferred stock upon which we will pay $9.7 million of dividends in 2001.

CAPITAL RESOURCES AND LIQUIDITY Our estimated 2001 cash uses, including drilling and development activities, are expected to be funded primarily through a combination of working capital and operating cash flow. The remainder, if any, is expected to be funded with borrowings from our Credit Facilities. The amount of operating cash flow to be generated during 2001 is uncertain due to the factors affecting revenues and expenses as previously cited. However, we expect combined capital resources to be more than adequate to fund anticipated capital expenditures and other cash uses for 2001. As of December 31, 2000, we had $853 million available under our $1 billion Credit Facilities. If significant acquisitions or other unplanned capital requirements arise during the year, we could utilize existing Credit Facilities and/or seek to establish and utilize other sources of financing.

IMPACT OF RECENTLY ISSUED ACCOUNTING STANDARDS NOT YET ADOPTED In June 1998, the Financial Accounting Standards Board issued Statement of Financial Accounting Standards No. 133, “Accounting for Derivative Instruments and Hedging Activities” (“SFAS 133”). In June 2000, it issued SFAS 138, which amended certain provisions of SFAS 133. SFAS 133, as amended, establishes accounting and reporting standards for derivative instruments, including certain derivative instruments embedded in other contracts, and for hedging activities. It requires the recognition of all derivatives as either assets or liabilities in the statement of financial position and measurement of those instruments at fair value. If certain conditions are met, a derivative may be specifically designated as a hedge. The accounting for changes in the fair value of a derivative (that is gains and losses) depends on the intended use of the derivative and whether it qualifies as a hedge. Devon adopted the provisions of SFAS 133, as amended, in the first quarter of the year ending December 31, 2001. In accordance with the transition provisions of SFAS 133, we recorded a net-of-tax cumulative-effect-type adjustment of $36.6 million in accumulated other comprehensive loss to recognize at fair value all derivatives that are designated as cash-flow hedging financial instruments. Additionally, we recorded a net-of-tax cumulative-effect-type adjustment to net earnings for a $49.5 million gain related to the fair value of financial instruments that do not qualify as hedges. This gain included $46.2 million related to the option embedded in our debentures that are exchangeable into shares of Chevron Corporation common stock.

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 our market risk sensitive instruments were entered into for purposes other than trading.

COMMODITY PRICE RISK Our major market risk exposure is in the pricing applicable to our oil and gas production. Realized pricing is primarily driven by the prevailing worldwide price for crude oil and spot market prices applicable to our U.S. and Canadian natural gas 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 our projected oil and natural gas production through various financial transactions which hedge the future prices received. These transactions include financial price swaps whereby we will receive a fixed price for our production and pay a variable market price to the contract counterparty. These transactions also include 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. Realized gains or losses from the settlement of these financial hedging instruments are recognized in oil and gas sales when the associated production occurs. The gains and losses realized as a result of these hedging activities are substantially offset in the cash market when the hedged commodity is delivered. Devon does not hold or issue derivative instruments for trading purposes.

As of year-end 2000, we had certain financial gas price hedging instruments in place. Subsequent to year-end 2000, we entered into additional financial transactions which hedge the future prices to be received for some of our natural gas production in 2001 and 2002. Our total hedged positions as of January 29, 2001, are set forth below for each of our operating divisions.

PRICE SWAPS Through various price swaps, we have fixed the price we will receive on a portion of our natural gas production in 2001 and 2002. The following tables include information on this production by division. 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.

	First Half of 2001		Second Half of 2001	
Division	Mcf/Day	Price/Mcf	Mcf/Day	Price/Mcf
Rocky Mountain	20,661	$ 1.90	57,955	$ 3.68
Gulf	—	$ —	40,000	$ 5.45
Canada	18,953	$ 1.68	17,404	$ 1.67

	First Half of 2002		Second Half of 2002	
Division	Mcf/Day	Price/Mcf	Mcf/Day	Price/Mcf
Rocky Mountain	26,395	$ 4.06	26,395	$ 4.06
Gulf	15,000	$ 4.62	15,000	$ 4.62
Canada	11,884	$ 1.73	6,294	$ 1.83

COSTLESS PRICE COLLARS We have also entered into costless price collars that set a floor and ceiling price for a portion of our 2001 and 2002 natural gas production. The following tables include information on these collars for each division. The floor and ceiling prices related to domestic production are based on various regional first-of-the-month price indices as published monthly by “Inside F.E.R.C.’s Gas Market Report.” The floor and ceiling prices related to Canadian production 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 our 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.

	First Half of 2001			Second Half of 2001		
Division	MMBtu/Day	Floor Price Per MMBtu	Ceiling Price Per MMBtu	MMBtu/Day	Floor Price Per MMBtu	Ceiling Price Per MMBtu
Rocky Mountain - El Paso	—	$ —	$ —	20,000	$ 4.10	$ 8.00

	First Half of 2002			Second Half of 2002		
Division	MMBtu/Day	Floor Price Per MMBtu	Ceiling Price Per MMBtu	MMBtu/Day	Floor Price Per MMBtu	Ceiling Price Per MMBtu
Rocky Mountain - El Paso	25,000	$ 3.25	$ 7.85	25,000	$ 3.25	$ 7.85
Rocky Mountain - CIG	80,000	$ 2.90	$ 6.75	80,000	$ 2.90	$ 6.75
Permian/Mid-Continent	81,800	$ 3.49	$ 7.25	81,800	$ 3.49	$ 7.25
Gulf	98,200	$ 3.49	$ 7.23	98,200	$ 3.49	$ 7.23
Canada	18,964	$ 3.27	$ 6.54	18,964	$ 3.27	$ 6.54

BASIS SWAP Devon has entered into a basis swap on 20,000 MMBtu of gas production per day that expires at the end of August 2004. Under the terms of the basis swap, the counterparty pays Devon the average NYMEX price for the last three trading days of each month, less $0.30, per MMBtu. In return, Devon pays the counterparty the CIG index price published by Inside FERC. The effect of this swap is included in Rocky Mountain Division gas revenues. This basis swap does not qualify as a hedge under the provisions of SFAS No. 133. Accordingly, fluctuations in the fair value of this basis swap will be recorded in earnings beginning in the first quarter of 2001.

We use 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, 2001, a 10% increase in the underlying commodities' prices would have reduced the fair value of our commodity hedging instruments by $33.7 million.

FIXED-PRICE PHYSICAL DELIVERY CONTRACTS In addition to the commodity hedging instruments described above, Devon also manages its exposure to oil and gas price risks by periodically entering into fixed-price contracts.

We have fixed the price we will receive on a portion of its 2001 and 2002 oil production through certain forward oil sales. From January 2001 through August 2002, 311,000 barrels of oil production per month have been fixed at an average price of $16.84 per barrel. These fixed-price barrels are attributable to the Permian/Mid-Continent Division.

For the years 2001 and 2002, Devon has fixed-price gas contracts that cover approximately 15 Bcf and 12 Bcf, respectively. For each of the years 2003 through 2006, Devon has fixed price contracts that cover 8 Bcf per year of Canadian production. We also have Canadian gas volumes subject to fixed-price contracts in the years from 2007 through 2016, but the yearly volumes are less than 6 Bcf.

INTEREST RATE RISK At December 31, 2000, we had long-term debt outstanding of $2.0 billion. Of this amount, $1.9 billion, or 93%, bears interest at fixed rates averaging 5.8%. The remaining $0.1 billion of debt outstanding at the end of 2000 bears interest at floating rates which averaged 6.1% at the end of 2000.

The terms of the Credit Facilities in place allow interest rates to be fixed at our option for periods of between 30 to 180 days. A 10% increase in short-term interest rates on the floating-rate debt outstanding as of December 31, 2000, would equal approximately 61 basis points. Such an increase in interest rates would increase our 2001 interest expense by approximately $0.9 million assuming borrowed amounts remain outstanding.

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 applicable 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.

Substantially all of our Canadian oil sales are paid in Canadian dollars, but at amounts based on the U.S. dollar price of oil. Therefore, currency fluctuations between the Canadian and U.S. dollars impact the amount of Canadian dollars received by Devon's Canadian subsidiaries for their oil production. To mitigate the effect of volatility in the Canadian-to-U.S. dollar exchange rate on Canadian oil revenues, we have existing foreign currency exchange rate swaps. Under such swap agreements, in 2001 we will sell $10 million at an average Canadian-to-U.S. exchange rate of $0.7102 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 oil sales. At the year-end 2000 exchange rate, these swaps would result in decreases to 2001's annual oil sales of approximately $0.6 million. A further $0.03 decrease in the Canadian-to-U.S. dollar exchange rate in 2001 would result in an additional decrease in oil sales of approximately $0.4 million.

For purposes of the sensitivity analysis described above for changes in the Canadian dollar exchange rate, a change in the rate of $0.03 was used as opposed to a 10% change in the rate. During the last eight 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 2000 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 generally accepted accounting principles. 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 as 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

J. Larry Nichols
President & CEO

John Richels
CEO, Northstar Energy

J. Michael Lacey
Senior Vice President

Darryl G. Smette
Senior Vice President

Duke R. Ligon
Senior Vice President

H. Allen Turner
Senior Vice President

Marian J. Moon
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, 2000, 1999 and 1998, 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 and 1998 financial statements of Santa Fe Snyder Corporation, a wholly-owned subsidiary, which statements reflect total assets constituting 24% and 38% in 1999 and 1998, respectively, of the related consolidated totals, and which statements reflect total revenues constituting 41% and 43% in 1999 and 1998, respectively, of the related consolidated totals. We did not audit the 1998 financial statements of Northstar Energy Corporation, a wholly-owned subsidiary, which statements reflect total assets constituting 20% of the related consolidated 1998 total, and which statements reflect total revenues constituting 22% in 1998 of the related consolidated totals. The 1999 and 1998 financial statements of Santa Fe Snyder Corporation and the 1998 financial statements of Northstar Energy Corporation were audited by other auditors whose reports have been furnished to us, and our opinion, insofar as it relates to the amounts included for Santa Fe Snyder Corporation in 1999 and 1998, and Northstar Energy Corporation in 1998, is based solely on the reports 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 reports of the other auditors provide a reasonable basis for our opinion.

In our opinion, based on our audits and the reports 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, 2000, 1999 and 1998, 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.

KPMG LLP

Oklahoma City, Oklahoma
January 30, 2001

DEVON ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

DECEMBER 31, (IN THOUSANDS, EXCEPTSHARE DATA)	**2000**	**1999**	**1998**
ASSETS			
Current assets:			
Cash and cash equivalents	$ **228,050**	173,167	31,254
Accounts receivable	**598,248**	316,005	137,058
Inventories	**47,272**	38,941	21,750
Deferred income taxes	**8,979**	4,886	605
Investments and other current assets	**51,588**	57,295	35,981
Total current assets	**934,137**	590,294	226,648
Property and equipment, at cost, based on the full cost method of accounting for oil and gas properties	**9,709,352**	8,592,010	4,854,211
Less accumulated depreciation, depletion and amortization	**4,799,816**	4,168,590	3,230,683
	4,909,536	4,423,420	1,623,528
Investment in Chevron Corporation common stock, at fair value	**598,867**	614,382	—
Deferred income taxes	**—**	—	54,381
Goodwill, net of amortization	**289,489**	322,800	—
Other assets	**128,449**	145,464	25,980
Total assets	$ **6,860,478**	6,096,360	1,930,537
LIABILITIES AND STOCKHOLDERS' EQUITY			
Current liabilities:			
Accounts payable:			
Trade	**320,713**	266,825	155,377
Revenues and royalties due to others	**116,481**	67,330	20,608
Income taxes payable	**65,674**	12,587	1,200
Accrued interest payable	**23,191**	28,370	5,588
Merger related expenses payable	**52,421**	35,704	7,882
Accrued expenses	**50,507**	56,528	29,201
Total current liabilities	**628,987**	467,344	219,856
Other liabilities	**164,469**	241,782	71,947
Debentures exchangeable into shares of Chevron Corporation common stock	**760,313**	760,313	—
Other long-term debt	**1,288,523**	1,656,208	735,871
Deferred revenue	**113,756**	104,800	3,600
Deferred income taxes	**626,826**	344,593	—
Company-obligated mandatorily redeemable convertible preferred securities of subsidiary trust holding solely 6.5% convertible junior subordinated debentures of Devon Energy Corporation	**—**	—	149,500
Stockholders' equity:			
Preferred stock of $1.00 par value ($100 liquidation value) Authorized 4,500,000 shares; issued 1,500,000 in 2000 and 1999 and none in 1998	**1,500**	1,500	—
Common stock of $.10 par value Authorized 400,000,000 shares; issued 128,638,000 in 2000, 126,323,000 in 1999 and 70,909,000 in 1998	**12,864**	12,632	7,090
Additional paid-in capital	**3,563,994**	3,491,828	1,523,944
Retained earnings (accumulated deficit)	**(214,708)**	(908,598)	(737,009)
Accumulated other comprehensive loss	**(85,397)**	(65,242)	(35,962)
Unamortized restricted stock awards	**(649)**	—	(1,500)
Treasury stock, at cost: 330,000 shares in 1999 and 176,000 shares in 1998	**—**	(10,800)	(6,800)
Total stockholders' equity	**3,277,604**	2,521,320	749,763
Commitments and contingencies (Notes 12 and 13)			
Total liabilities and stockholders' equity	$ **6,860,478**	6,096,360	1,930,537

See accompanying notes to consolidated financial statements

DEVON ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

YEAR ENDED DECEMBER 31, (IN THOUSANDS, EXCEPTPER SHARE AMOUNTS)	**2000**	**1999**	**1998**
REVENUES			
Oil sales	**$ 1,078,759**	561,018	309,990
Gas sales	**1,485,221**	627,869	347,273
Natural gas liquids sales	**154,465**	67,985	24,715
Other	**65,658**	20,596	24,248
Total revenues	**2,784,103**	1,277,468	706,226
COSTS AND EXPENSES			
Lease operating expenses	**440,780**	298,807	226,561
Transportation costs	**53,309**	33,925	23,186
Production taxes	**103,244**	44,740	24,871
Depreciation, depletion and amortization of property and equipment	**693,340**	406,375	243,144
Amortization of goodwill	**41,332**	16,111	—
General and administrative expenses	**93,008**	80,645	45,454
Expenses related to mergers	**60,373**	16,800	13,149
Interest expense	**154,329**	109,613	43,532
Deferred effect of changes in foreign currency exchange rate on subsidiary's long-term debt	**2,408**	(13,154)	16,104
Distributions on preferred securities of subsidiary trust	**—**	6,884	9,717
Reduction of carrying value of oil and gas properties	**—**	476,100	422,500
Total costs and expenses	**1,642,123**	1,476,846	1,068,218
Earnings (loss) before income tax expense (benefit) and extraordinary item	**1,141,980**	(199,378)	(361,992)
INCOME TAX EXPENSE (BENEFIT)			
Current	**130,793**	23,056	(3,713)
Deferred	**280,845**	(72,490)	(122,394)
Total income tax expense (benefit)	**411,638**	(49,434)	(126,107)
Earnings (loss) before extraordinary item	**730,342**	(149,944)	(235,885)
Extraordinary loss	**—**	(4,200)	—
Net earnings (loss)	**730,342**	(154,144)	(235,885)
Preferred stock dividends	**9,735**	3,651	—
Net earnings (loss) applicable to common shareholders	**$ 720,607**	(157,795)	(235,885)
Net earnings (loss) per average common share outstanding:			
Before extraordinary loss:			
Basic	**$ 5.66**	(1.64)	(3.32)
Diluted	**$ 5.50**	(1.64)	(3.32)
After extraordinary loss:			
Basic	**$ 5.66**	(1.68)	(3.32)
Diluted	**$ 5.50**	(1.68)	(3.32)
Weighted average common shares outstanding:			
Basic	**127,421**	93,653	70,948
Diluted	**131,730**	99,313	76,932

See accompanying notes to consolidated financial statements

DEVON ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

(IN THOUSANDS)	PREFERRED STOCK	COMMON STOCK	ADDITIONAL PAID-IN CAPITAL	RETAINED EARNINGS (ACCUMULATED DEFICIT)	ACCUMULATED OTHER COMPRE-HENSIVE LOSS	UNAMORTIZED RESTRICTED STOCK AWARDS	TREASURY STOCK	TOTAL STOCK-HOLDERS' EQUITY
BALANCE AS OF DECEMBER 31, 1997	$ —	7,077	1,521,128	(493,246)	(27,113)	(700)	(600)	1,006,546
Comprehensive loss:								
Net loss	—	—	—	(235,885)	—	—	—	(235,885)
Other comprehensive loss, net of tax:								
Foreign currency translation adjustments	—	—	—	—	(8,130)	—	—	(8,130)
Minimum pension liability adjustment	—	—	—	—	(719)	—	—	(719)
Other comprehensive loss	—	—	—	—	—	—	—	(8,849)
Comprehensive loss	—	—	—	—	—	—	—	(244,734)
Stock issued	—	13	2,816	(600)	—	(2,600)	5,400	5,029
Stock repurchased	—	—	—	—	—	—	(11,600)	(11,600)
Dividends on common stock	—	—	—	(7,278)	—	—	—	(7,278)
Amortization of restricted stock awards	—	—	—	—	—	1,800	—	1,800
BALANCE AS OF DECEMBER 31, 1998	—	7,090	1,523,944	(737,009)	(35,962)	(1,500)	(6,800)	749,763
Comprehensive loss:								
Net loss	—	—	—	(154,144)	—	—	—	(154,144)
Other comprehensive loss, net of tax:								
Foreign currency translation adjustments	—	—	—	—	7,517	—	—	7,517
Minimum pension liability adjustment	—	—	—	—	(241)	—	—	(241)
Unrealized losses on marketable securities	—	—	—	—	(36,556)	—	—	(36,556)
Other comprehensive loss	—	—	—	—	—	—	—	(29,280)
Comprehensive loss	—	—	—	—	—	—	—	(183,424)
Stock issued	**1,500**	5,542	1,966,930	(1,100)	—	(100)	7,600	1,980,372
Stock repurchased	—	—	—	—	—	—	(11,600)	(11,600)
Tax benefit related to employee stock options	—	—	954	—	—	—	—	954
Dividends on common stock	—	—	—	(12,694)	—	—	—	(12,694)
Dividends on preferred stock	—	—	—	(3,651)	—	—	—	(3,651)
Amortization of restricted stock awards	—	—	—	—	—	1,600	—	1,600
BALANCE AS OF DECEMBER 31, 1999	**1,500**	12,632	3,491,828	(908,598)	(65,242)	—	(10,800)	2,521,320
Comprehensive income:								
Net income	—	—	—	730,342	—	—	—	730,342
Other comprehensive loss, net of tax:								
Foreign currency translation adjustments	—	—	—	—	(10,213)	—	—	(10,213)
Minimum pension liability adjustment	—	—	—	—	822	—	—	822
Unrealized losses on marketable securities	—	—	—	—	(10,764)	—	—	(10,764)
Other comprehensive loss	—	—	—	—	—	—	—	(20,155)
Comprehensive income	—	—	—	—	—	—	—	710,187
Stock issued	—	232	69,163	(4,497)	—	—	21,499	86,397
Stock repurchased	—	—	—	—	—	—	(10,699)	(10,699)
Tax benefit related to employee stock options	—	—	3,003	—	—	—	—	3,003
Dividends on common stock	—	—	—	(22,220)	—	—	—	(22,220)
Dividends on preferred stock	—	—	—	(9,735)	—	—	—	(9,735)
Grant of restricted stock awards	—	—	—	—	—	(5,217)	—	(5,217)
Forfeiture of restricted stock awards	—	—	—	—	—	129	—	129
Amortization of restricted stock awards	—	—	—	—	—	4,439	—	4,439
BALANCE AS OF DECEMBER 31, 2000	**$ 1,500**	**12,864**	**3,563,994**	**(214,708)**	**(85,397)**	**(649)**	**—**	**3,277,604**

See accompanying notes to consolidated financial statements

DEVON ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

YEAR ENDED DECEMBER 31, (IN THOUSANDS)	2000	1999	1998
CASH FLOWS FROM OPERATING ACTIVITIES			
Net earnings (loss)	**$ 730,342**	(154,144)	(235,885)
Adjustments to reconcile net earnings (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization of property and equipment	**693,340**	406,375	243,144
Amortization of goodwill	**41,332**	16,111	—
Accretion of interest on zero-coupon convertible senior debentures	**6,950**	—	—
Amortization of (premiums) discounts on other long-term debt, net	**(3,781)**	(728)	100
Deferred effect of changes in foreign currency exchange rate on subsidiary's long-term debt	**2,408**	(13,154)	16,104
Reduction of carrying value of oil and gas properties	**—**	476,100	422,500
(Gain) loss on sale of assets	**(683)**	4,778	(264)
Deferred income tax expense (benefit)	**280,845**	(72,490)	(122,394)
Other	**3,849**	2,100	4,801
Changes in assets and liabilities, net of effects of acquisitions of businesses:			
(Increase) decrease in:			
Accounts receivable	**(283,787)**	(92,416)	30,760
Inventories	**(8,322)**	(8,514)	(1,427)
Prepaid expenses	**5,825**	(4,418)	(7,751)
Other assets	**3,812**	(36,673)	17,230
Increase (decrease) in:			
Accounts payable	**98,912**	(22,495)	(19,439)
Income taxes payable	**60,548**	(19,318)	(10,426)
Accrued expenses	**3,104**	(38,387)	1,000
Deferred revenue	**7,954**	90,700	(100)
Long-term other liabilities	**(23,616)**	(1,099)	(3,482)
Net cash provided by operating activities	**1,619,032**	532,328	334,471
CASH FLOWS FROM INVESTING ACTIVITIES			
Proceeds from sale of property and equipment	**101,531**	114,384	64,997
Proceeds from sale of investments	**12,781**	—	42,584
Capital expenditures	**(1,280,132)**	(883,420)	(712,812)
(Increase) decrease in other assets	**(7,581)**	719	(2,029)
Net cash used in investing activities	**(1,173,401)**	(768,317)	(607,260)
CASH FLOWS FROM FINANCING ACTIVITIES			
Proceeds from borrowings of long-term debt, net of issuance costs	**2,580,086**	1,944,417	1,506,220
Principal payments on long-term debt	**(2,951,711)**	(2,089,109)	(1,242,013)
Issuance of common stock, net of issuance costs	**51,550**	530,232	4,429
Retirement of preferred securities of subsidiary trust	**—**	(50)	—
Repurchase of common stock	**(10,699)**	(11,600)	(11,600)
Issuance of treasury stock	**24,937**	6,200	—
Dividends paid on common stock	**(22,220)**	(12,694)	(7,278)
Dividends paid on preferred stock	**(9,735)**	(3,651)	—
(Decrease) increase in long-term other liabilities	**(51,779)**	13,453	6,760
Net cash (used in) provided by financing activities	**(389,571)**	377,198	256,518
Effect of exchange rate changes on cash	**(1,177)**	704	(140)
Net increase (decrease) in cash and cash equivalents	**54,883**	141,913	(16,411)
Cash and cash equivalents at beginning of year	**173,167**	31,254	47,665
Cash and cash equivalents at end of year	**$ 228,050**	173,167	31,254

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, and 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.

Information concerning common stock and per share data assumes the exchange of all Exchangeable Shares issued in connection with the Northstar combination described in Note 2.

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.

Inventories

Inventories, which consist primarily of injected gas and tubular goods, parts and supplies, are stated at cost, determined principally by the average cost method, which is not in excess of net realizable value.

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. 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. Such limitations are imposed separately on a country-by-country basis. 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. 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.

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 Chevron 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, is amortized by an equivalent unit-of-production method. Devon assesses the recoverability of this intangible asset 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 $57.4 million and $16.1 million at December 31, 2000 and 1999, respectively.

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 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. 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.

Devon accounts for its hedging instruments using the deferral method of accounting. Under this method, realized gains and losses from Devon's price risk management activities are recognized in oil and gas revenues when the associated production occurs and the resulting cash flows are reported as cash flows from operating activities. Gains and losses on hedging contracts that are closed before the hedged production occurs are deferred until the production month originally hedged. In the event of a loss of correlation between changes in oil and gas reference prices under a hedging instrument and actual oil and gas prices, a gain or loss is recognized currently to the extent the hedging instrument has not offset changes in actual oil and gas prices.

Devon adopted the provisions of SFAS 133, as amended, in the first quarter of the year ending December 31, 2001. In accordance with the transition provisions of SFAS 133, Devon recorded a net-of-tax cumulative-effect-type adjustment of $36.6 million in accumulated other comprehensive loss to recognize at fair value all derivatives that are designated as cash-flow hedging financial instruments. Additionally, Devon recorded a net-of-tax cumulative-effect-type adjustment to net earnings for a $49.5 million gain related to the fair value of financial instruments that do not qualify as hedges. This gain included $46.2 million related to the option embedded in Devon's debentures that are exchangeable into shares of Chevron Corporation common stock.

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 2000, Enron Capital and Trade Resource Corporation accounted for 20% of Devon's combined oil, gas and natural gas liquids sales. In 1998, Aquila Energy Marketing Corporation accounted for 11% of Devon's combined oil, gas and natural gas liquids sales. No purchaser accounted for over 10% of such revenues in 1999.

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 2000. The diluted loss per share calculations for 1999 and 1998 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. The diluted calculation for 1998 reduced the net loss by $6.0 million and increased the common shares outstanding by 6.0 million shares.) Therefore, the diluted loss per share amounts for 1999 and 1998 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 THOUSANDS)	
YEAR ENDED DECEMBER 31, 2000:			
Basic earnings per share	$ 720,607	127,421	$ 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 $2,755,000)	4,309	2,248	
Potential common shares issuable upon the exercise of outstanding stock options	—	2,061	
Diluted earnings per share	$ 724,916	131,730	$ 5.50

Options to purchase approximately 1.0 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. The excluded options for 2000 expire between February 12, 2001 and June 1, 2010. All options were excluded from the diluted earnings per share calculations for 1999 and 1998.

Comprehensive Loss

Devon's comprehensive income information is included in the accompanying consolidated statements of stockholders' equity. A summary of accumulated other comprehensive loss as of December 31, 2000, 1999 and 1998, and changes during each of the years then ended, is presented in the following table.

	FOREIGN CURRENCY TRANSLATION ADJUSTMENTS	MINIMUM PENSION LIABILITY ADJUSTMENTS	UNREALIZED LOSSES ON MARKETABLE SECURITIES	TOTAL
		(IN THOUSANDS)		
Balance as of December 31, 1997	$ (27,113)	—	—	(27,113)
1998 activity	(8,130)	(1,179)	—	(9,309)
Deferred taxes	—	460	—	460
1998 activity, net of deferred taxes	(8,130)	(719)	—	(8,849)
Balance as of December 31, 1998	(35,243)	(719)	—	(35,962)
1999 activity	7,517	(394)	(59,959)	(52,836)
Deferred taxes	—	153	23,403	23,556
1999 activity, net of deferred taxes	7,517	(241)	(36,556)	(29,280)
Balance as of December 31, 1999	(27,726)	(960)	(36,556)	(65,242)
2000 activity	(10,213)	1,346	(17,608)	(26,475)
Deferred taxes	—	(524)	6,844	6,320
2000 activity, net of deferred taxes	(10,213)	822	(10,764)	(20,155)
Balance as of December 31, 2000	$ (37,939)	(138)	(47,320)	(85,397)

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 2000, 1999 and 1998 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 and the Northstar combination, annual dividends per share for 2000, 1999 and 1998 were $0.17, $0.14 and $0.10, 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 1999 and 1998 amounts in the accompanying consolidated financial statements have been reclassified to conform to the 2000 presentation.

2. BUSINESS COMBINATIONS AND PRO FORMA INFORMATION

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 40.6 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 $60.4 million ($37.2 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 21.5 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. The calculation of the total purchase price and the allocation to assets and liabilities as of August 17, 1999, are shown below. Devon has sold certain of the assets acquired. Generally, the proceeds from such sales reduced the carrying value of oil and gas properties.

	(IN THOUSANDS, EXCEPTSHARE PRICE)
Calculation and allocation of purchase price:	
Shares of Devon common stock issued to PennzEnergy stockholders	21,501
Average Devon stock price	$ 33.40
Fair value of common stock issued	$ 718,177
Plus preferred stock assumed by Devon	150,000
Plus estimated merger costs incurred	71,545
Plus fair value of PennzEnergy employee stock options assumed by Devon	18,295
Less stock registration and issuance costs incurred	(4,985)
Total purchase price	953,032
Plus fair value of liabilities assumed by Devon:	
Current liabilities	200,708
Debentures exchangeable into Chevron Corporation common stock	760,313
Other long-term debt	838,792
Other long-term liabilities	158,988
	2,911,833
Less fair value of non oil and gas assets acquired by Devon:	
Current assets	109,769
Non oil and gas properties	31,412
Investment in common stock of Chevron Corporation	676,441
Other assets	81,945
Fair value allocated to oil and gas properties, including $83.3 million of undeveloped leasehold	$ 2,012,266

Additionally, $346.9 million was added as goodwill for deferred taxes 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 $346.9 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.

Estimated proved reserves added in the PennzEnergy merger were 232.7 million barrels of oil, 782.6 billion cubic feet of natural gas and 32.7 million barrels of natural gas liquids. Also, added in the PennzEnergy merger were approximately 13 million net acres of undeveloped leasehold. (The quantities of proved reserves stated in this paragraph are unaudited.)

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 15.1 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. The calculation of the total purchase price and the allocation to assets and liabilities as of May 5, 1999, are as follows.

	(IN THOUSANDS, EXCEPTSHARE PRICE)	
Calculation and allocation of purchase price:		
Shares of Santa Fe common stock issued to Snyder stockholders, as adjusted for the Devon-Santa Fe Snyder pooling		15,130
Average Santa Fe stock price, as adjusted for the Devon-Santa Fe Snyder pooling	$	27.24
Fair value of common stock issued	$	412,092
Plus estimated merger costs incurred		1,485
Total purchase price		413,577
Plus fair value of liabilities assumed:		
Current liabilities		55,118
Long-term debt		219,001
Other long-term liabilities		26,254
		713,950
Less fair value of non oil and gas assets acquired:		
Current assets		16,755
Other assets		37,211
Fair value allocated to oil and gas properties, including $14.7 million of undeveloped leasehold	$	659,984

Additionally, $135.4 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 $135.4 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.

Estimated proved reserves added in the Snyder merger were 17.7 million barrels of oil and natural gas liquids and 424 billion cubic feet of natural gas. Also added in the Snyder merger were approximately 800,000 net acres of undeveloped leasehold. (The quantities of proved reserves stated in this paragraph are unaudited.)

Wascana Properties Transaction

On December 23, 1998, Devon acquired certain natural gas properties located in northeastern Alberta, Canada, from Wascana Oil and Gas Partnership, a subsidiary of Canadian Occidental Petroleums Ltd. (the "Wascana Properties"). Devon acquired the properties for approximately $57.5 million, which was funded with bank debt under Devon's then existing credit facilities.

Estimated proved reserves of the Wascana Properties as of December 31, 1998, were 71.5 billion cubic feet of natural gas. Approximately $52.2 million of the purchase price was allocated to the proved reserves. The remaining $5.3 million of the purchase price was allocated to approximately 190,000 net undeveloped acres and exclusive rights to associated seismic data. (The quantities of proved reserves stated in this paragraph are unaudited.)

Pro Forma Information (Unaudited)

Set forth in the following table is certain unaudited pro forma financial information for the years ended December 31, 1999 and 1998. This information has been prepared assuming the PennzEnergy merger, the Snyder merger and the Wascana Property transaction were consummated on January 1, 1998, and 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, 1998. The pro forma information also should not be used as an indication of the future results that Devon will achieve after the transactions.

The pro forma information includes the effect of Devon's issuance of 10.3 million shares of common stock as if such shares had been issued on January 1, 1998. (See Note 10 for additional information on this issuance of shares of common stock.) The pro forma information assumes that the approximately $402 million of net proceeds from the issuance of common stock was used to retire long-term debt and therefore reduce interest expense.

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

• Expected annual cost savings of $30 to $35 million related to the Santa Fe Snyder merger and $50 to $60 million related to the PennzEnergy merger have not been reflected as an adjustment to the historical data in preparing the following pro forma information. These cost savings are expected to result from the consolidation of the corporate headquarters of Devon, Santa Fe Snyder and PennzEnergy and the elimination of duplicate staff and expenses. Some of the cost savings related to the Santa Fe Snyder merger involve items that, under the full cost method of accounting, are capitalized rather than expensed in the consolidated financial statements. Therefore, not all of the $30 to $35 million of expected savings will result in reductions to expenses as reported in the accompanying consolidated statements of operations.

• The 1999 pro forma results include a gain of $46.7 million ($29.8 million after-tax) from PennzEnergy's pre-merger sale of land, timber and mineral rights in Pennsylvania and New York.

• In 1998, PennzEnergy realized pretax gains on the sale and exchange of Chevron Corporation common stock of $203.1 million. This gain is included in the 1998 pro forma financial information presented in the following table. The pro forma financial information does not include the related $207.0 million after-tax extraordinary loss resulting from the early extinguishment of debt. The exclusion of the extraordinary loss from the 1998 pro forma results is required by Securities and Exchange Commission rules and regulations regarding presentation of pro forma results of operations. If the extraordinary loss were included in the 1998 pro forma results, the 1998 pro forma net loss as presented in the following table would be $508.8 million, or $4.37 per share.

• The 1999 pro forma financial information does not include a $4.2 million extraordinary loss recorded by Santa Fe Snyder. This loss related to the early extinguishment of debt. If the extraordinary loss were included in the 1999 pro forma results, the 1999 pro forma net loss as presented in the following table would be $211.9 million, or $1.85 per share.

• The 1998 pro forma results include $24.3 million of nonrecurring general and administrative expenses in connection with the spin-off of Pennzoil-Quaker State Company on December 30, 1998.

• The 1999 and 1998 pro forma results include reductions of the carrying value of oil and gas properties of $476.1 million and $422.5 million, respectively. The after-tax effect of these reductions, which were due to the full cost ceiling limitation, were $309.7 million in 1999 and $280.8 million in 1998.

YEAR ENDED DECEMBER 31,	PRO FORMA INFORMATION 1999	1998
	(DOLLARS IN THOUSANDS, EXCEPT PER SHARE AMOUNTS)	
REVENUES		
Oil sales	$ 702,477	487,218
Gas sales	806,337	802,785
Natural gas liquids sales	93,829	71,726
Other	87,453	306,103
Total revenues	1,690,096	1,667,832
COSTS AND EXPENSES		
Lease operating expenses	409,555	444,617
Production taxes	53,506	44,548
Depreciation, depletion and amortization of property and equipment	665,865	723,908
Amortization of goodwill	46,321	52,637
General and administrative expenses	147,028	177,678
Expenses related to prior mergers	16,800	13,149
Interest expense	158,813	175,082
Deferred effect of changes in foreign currency exchange rate on subsidiary's long-term debt	(13,154)	16,104
Distributions on preferred securities of subsidiary trust	6,884	9,717
Reduction of carrying value of oil and gas properties	476,100	422,500
Total costs and expenses	1,967,718	2,079,940
Earnings (loss) before income tax expense (benefit) and extraordinary item	(277,622)	(412,108)
INCOME TAX EXPENSE (BENEFIT)		
Current	23,261	(1,076)
Deferred	(93,173)	(109,222)
Total income tax expense (benefit)	(69,912)	(110,298)
Earnings (loss) before extraordinary item	(207,710)	(301,810)
Preferred stock dividends	9,736	5,625
Earnings (loss) before extraordinary item applicable to common stockholders	$ (217,446)	(307,435)
Earnings (loss) before extraordinary item per average common share outstanding - basic and diluted	$ (1.81)	(2.61)
Weighted average common shares outstanding - basic	119,988	117,703

Northstar Combination

On June 29, 1998, Devon and Northstar Energy Corporation ("Northstar") announced they had entered into a definitive combination agreement subject to shareholder approval and certain other conditions. The combination of the two companies (the "Northstar combination") was closed on December 10, 1998. At that date, Northstar became a wholly-owned subsidiary of Devon. Pursuant to the Northstar combination, Northstar's common shareholders received approximately 16.1 million exchangeable shares (the "Exchangeable Shares") based on an exchange ratio of 0.235 Exchangeable Shares for each Northstar common share outstanding. The Exchangeable Shares were issued by Northstar, but are exchangeable at any time into Devon's common shares on a one-for-one basis. Prior to such exchange, the Exchangeable Shares have rights identical to those of Devon's common shares, including dividend, voting and liquidation rights. Between December 10, 1998 and December 31, 2000, approximately 13.1 million of the originally issued 16.1 million Exchangeable Shares had been exchanged for shares of Devon common stock.

The Northstar combination was accounted for under the pooling-of-interests method of accounting for business combinations. All operational and financial information contained herein includes the combined amounts for Devon and Northstar for all periods presented.

During the fourth quarter of 1998, Devon recorded a pre-tax charge of $13.1 million ($9.7 million after tax) for direct costs related to the Northstar combination.

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, 1999 and 1998, the San Juan Basin Transaction added approximately $12.3 million, $7.6 million and $8.4 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 $16.6 million and $6.8 million in 1999 and 1998, respectively, which were added to the repurchase liability. The actual repurchase price as of September 30, 2000, was approximately $36.3 million.

4. SUPPLEMENTAL CASH FLOW INFORMATION

Cash payments for interest in 2000, 1999 and 1998 were approximately $155.1 million, $115.6 million and $45.6 million, respectively. Cash payments for federal, state and foreign income taxes in 2000, 1999 and 1998 were approximately $81.8 million, $15.8 million and $19.4 million, respectively.

The 1999 PennzEnergy merger and Snyder merger involved non-cash consideration as presented below:

	1999 (IN THOUSANDS)
Value of common stock issued	$ 1,130,269
Value of preferred stock issued	150,000
Employee stock options assumed	18,295
Liabilities assumed	2,259,174
Deferred tax liability created	474,306
Fair value of assets acquired with non-cash consideration	$ 4,032,044

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,		2000	1999	1998
			(IN THOUSANDS)	
Oil, gas and natural gas liquids revenue accruals	$	**438,304**	218,462	74,660
Joint interest billings		**122,778**	66,658	33,136
Other		**41,013**	34,585	31,262
		602,095	319,705	139,058
Allowance for doubtful accounts		**(3,847)**	(3,700)	(2,000)
Net accounts receivable	$	**598,248**	316,005	137,058

6. PROPERTY AND EQUIPMENT

Property and equipment included the following:

DECEMBER 31,		2000	1999	1998
			(IN THOUSANDS)	
Oil and gas properties:				
Subject to amortization	$	**9,169,593**	8,125,886	4,584,676
Not subject to amortization:				
Acquired in 2000		**74,164**	—	—
Acquired in 1999		**122,431**	134,966	—
Acquired in 1998		**44,833**	56,922	65,702
Acquired prior to 1998		**73,832**	109,297	147,875
Accumulated depreciation, depletion and amortization		**(4,752,670)**	(4,129,824)	(3,204,775)
Net oil and gas properties		**4,732,183**	4,297,247	1,593,478
Other property and equipment		**224,499**	164,939	55,958
Accumulated depreciation and amortization		**(47,146)**	(38,766)	(25,908)
Net other property and equipment		**177,353**	126,173	30,050
Property and equipment, net of accumulated depreciation, depletion and amortization	$	**4,909,536**	4,423,420	1,623,528

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

YEAR ENDED DECEMBER 31,		2000	1999	1998
			(IN THOUSANDS)	
Depreciation, depletion and amortization of oil and gas properties	$	**662,890**	390,117	230,419
Depreciation and amortization of other property and equipment		**22,974**	13,660	12,564
Amortization of other assets		**7,476**	2,598	161
Total expense	$	**693,340**	406,375	243,144

7. LONG-TERM DEBT AND RELATED EXPENSES

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

DECEMBER 31,	2000	1999	1998
		(IN THOUSANDS)	
Borrowings under credit facilities with banks	**$ 146,652**	645,141	411,271
Debentures exchangeable into shares of Chevron Corporation common stock:			
4.90% due August 15, 2008	**443,807**	443,807	—
4.95% due August 15, 2008	**316,506**	316,506	—
Zero coupon convertible senior debentures exchangeable into shares of Devon Energy Corp. common stock, 3.875% due June 27, 2020	**359,689**	—	—
Other debentures:			
10.25% due November 1, 2005	**250,000**	250,000	—
10.125% due November 15, 2009	**200,000**	200,000	—
11.00% due May 15, 2004	**—**	—	100,000
Premium (discount) on debentures	**33,375**	37,467	(400)
Senior notes:			
8.05% due June 15, 2004	**124,881**	125,000	—
6.76% due July 19, 2005	**—**	75,000	75,000
8.75% due June 15, 2007	**175,000**	175,000	—
6.79% due March 2, 2009	**—**	150,000	150,000
Discount on notes	**(1,074)**	(1,400)	—
	2,048,836	2,416,521	735,871
Less amount classified as current	**—**	—	—
Long-term debt	**$ 2,048,836**	2,416,521	735,871

Maturities of long-term debt as of December 31, 2000, excluding the $32.3 million of premiums net of discounts, are as follows (in thousands):

2001	$ —
2002	7,333
2003	7,333
2004	132,213
2005	257,332
2006 and thereafter	1,612,324
Total	$ 2,016,535

Credit Facilities With Banks

Concurrent with the closing of the Santa Fe Snyder merger on August 29, 2000, Devon entered into new 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 Credit Facilities replaced the prior separate facilities of Devon and Santa Fe Snyder. Prior to the August 2000 merger, Devon and Santa Fe Snyder each had their own unsecured credit facilities. Devon's credit facilities prior to the merger aggregated $750 million, with $475 million in a U.S. facility and $275 million in a Canadian facility. Santa Fe Snyder's credit facilities prior to the merger aggregated $600 million.

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 28, 2001 (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 28, 2001 (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 $146.7 million outstanding under the Credit Facilities at December 31, 2000, was 6.07%. The average interest rate on bank debt outstanding under the previous facilities at December 31, 1999 and 1998 was 6.85% and 6.28%, respectively.

The agreements governing the Credit Facilities contain certain covenants and restrictions, including a maximum debt-to-capitalization ratio. At December 31, 2000, Devon was in compliance with such covenants and restrictions.

Exchangeable Debentures

The exchangeable debentures consist of $443.8 million of 4.90% debentures and $316.5 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 Chevron Corporation common stock. In lieu of delivering Chevron Corporation common stock, Devon may, at its option, pay to any holder an amount of cash equal to the market value of the Chevron 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 - either in cash or in a combination of cash and Chevron Corporation common stock.

As of December 31, 2000, Devon beneficially owned approximately 7.1 million shares of Chevron 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 Chevron Corporation common stock, an exchange rate equivalent to $107-7/32 per share of Chevron 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.

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 $250 million of 10.25% debentures and $200 million of 10.125% debentures, respectively. The premiums are being amortized using the effective interest method.

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 $125.0 million of 8.05% notes due 2004. The notes were issued for 98.758% of face value and Devon received total proceeds of $121.6 million after deducting related costs and expenses of $1.9 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.

In September 2000, Devon, as required under the $125 million senior note agreement due to a “change of control”, made a tender offer to repurchase the senior notes at a premium of 101.000%. As a result of this tender offer, $119,000 of senior notes were redeemed at a total cost to Devon of approximately $120,000.

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 $346.1 million, net of debt issuance costs of approximately $6.6 million. Devon used the proceeds from the sale of these debentures to pay down other domestic long-term debt.

Interest Expense

Following are the components of interest expense for the years 2000, 1999 and 1998:

YEAR ENDED DECEMBER 31,	2000	1999	1998
		(IN THOUSANDS)	
Interest based on debt outstanding	**$ 157,028**	108,064	43,114
Amortization of debt premium, net	**(3,781)**	(1,328)	—
Facility and agency fees	**2,696**	1,930	932
Amortization of capitalized loan costs	**1,467**	1,583	556
Capitalized interest	**(3,239)**	(1,925)	(1,100)
Other	**158**	1,289	30
Total interest expense	**$ 154,329**	109,613	43,532

Deferred Effect of Changes in Foreign Currency Exchange Rate on Long-term Debt

Until mid-January 2000, the 6.76 % and 6.79% fixed-rate Senior Notes referred to in the first table of this note were payable by Northstar. However, the notes were 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 increased or decreased the expected amount of Canadian dollars eventually required to repay the notes. Such changes in the Canadian dollar equivalent of the debt were 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 2000 and 1998 and increased in 1999. Therefore, $2.4 million of increased expense was recorded in 2000, $13.2 million of reduced expense was recorded in 1999, and $16.1 million of increased expense was recorded in 1998.

8. INCOME TAXES

At December 31, 2000, Devon had the following carryforwards available to reduce future income taxes:

TYPES OF CARRYFORWARD	YEARS OF EXPIRATION	CARRYFORWARD AMOUNTS
	(IN THOUSANDS)	
Net operating loss - U.S. federal	2008 - 2014	$ 344,038
Net operating loss - various states	2002 - 2014	$ 37,357
Net operating loss - Canada	2001 - 2007	$ 2,180
Minimum tax credits	Indefinite	$ 84,991

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

The earnings (loss) before income taxes and the components of income tax expense (benefit) for the years 2000, 1999 and 1998 were as follows:

YEAR ENDED DECEMBER 31,		2000	1999	1998
			(IN THOUSANDS)	
Earnings (loss) before income taxes:				
U.S	$	**872,455**	(313,101)	(274,150)
Canada		**156,085**	57,402	19,958
International		**113,440**	56,321	(107,800)
Total	$	**1,141,980**	(199,378)	(361,992)
Current income tax expense (benefit):				
U.S. federal	$	**106,742**	12,544	(6,399)
Various states		**6,015**	2,804	(1,189)
Canada		**2,268**	2,908	1,975
Other		**15,768**	4,800	1,900
Total current tax expense (benefit)		**130,793**	23,056	(3,713)
Deferred income tax expense (benefit):				
U.S. federal		**151,832**	(119,286)	(88,824)
Various states		**33,399**	(495)	(4,836)
Canada		**67,318**	26,654	11,166
Other		**28,296**	20,637	(39,900)
Total deferred tax expense (benefit)		**280,845**	(72,490)	(122,394)
Total income tax expense (benefit)	$	**411,638**	(49,434)	(126,107)

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

YEAR ENDED DECEMBER 31,	2000	1999	1998
U.S. statutory tax (benefit) rate	**35%**	(35)%	(35)%
Benefit from disposition of certain foreign assets	**(11)**	—	—
Non-deductible expenses	**3**	3	3
Nonconventional fuel source credits	**(2)**	(3)	(1)
State income taxes	**2**	1	(1)
Taxation on foreign operations	**5**	7	2
Other	**4**	2	(3)
Effective income tax (benefit) rate	**36%**	(25)%	(35)%

The tax effects of temporary differences that gave rise to significant portions of the deferred tax assets and liabilities at December 31, 2000, 1999 and 1998 are presented below:

DECEMBER 31,	2000	1999	1998
		(IN THOUSANDS)	
Deferred tax assets:			
Net operating loss carryforwards	$ **122,843**	207,322	48,418
Minimum tax credit carryforwards	**84,991**	88,447	16,900
Production payments	**—**	21,527	19,105
Long-term debt	**17,176**	17,583	—
Other	**95,283**	50,618	20,388
Total gross deferred tax assets	**320,293**	385,497	104,811
Less valuation allowance	**100**	100	100
Net deferred tax assets	**320,193**	385,397	104,711
Deferred tax liabilities:			
Property and equipment, principally due to differences in depreciation, and the expensing of intangible drilling costs for tax purposes	**(687,473)**	(500,156)	(49,256)
Chevron Corporation common stock	**(166,596)**	(172,631)	—
Other	**(83,971)**	(31,789)	(469)
Total deferred tax liabilities	**(938,040)**	(704,576)	(49,725)
Net deferred tax (liability) asset	$ **(617,847)**	(319,179)	54,986

As shown in the above table, Devon has recognized $320.2 million of net deferred tax assets as of December 31, 2000. Such amount consists primarily of $207.8 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 2001 and 2007, 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 2001 and 2006. 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. A $0.1 million valuation allowance has been recorded at December 31, 2000, related to depletion carryforwards acquired in a 1994 merger.

9. TRUST CONVERTIBLE PREFERRED SECURITIES

On July 10, 1996, Devon, through its affiliate Devon Financing Trust, completed the issuance of $149.5 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 $149.5 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 TCPSecurities 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, or $50,000 total, 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 $402.7 million from the sale of approximately 10.3 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 $0.8 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 21.5 million shares of Devon common stock issued on August 17, 1999, in connection with the PennzEnergy merger. Also, as discussed in Note 2, there were 16.1 million Exchangeable Shares issued on December 10, 1998, in connection with the Northstar combination. As of year-end 2000, 13.1 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 1.0 million 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 share rights plan described later in this note. At December 31, 2000, 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, 2000, there were 109,000 and 487,540 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 ten 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, 2000, there were 3,306,329 options outstanding under the 1997 Plan. There were 6,225,949 options available for future grants as of December 31, 2000.

In addition to the stock options outstanding under the 1988 Plan, 1993 Plan and 1997 Plan, there were approximately 1,744,409, 1,630,123 and 78,553 stock options outstanding at the end of 2000 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, 1998, 1999 and 2000, 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, 1997	4,405,560	$ 31.564	2,744,115	$ 29.717
Options granted	1,652,789	$ 34.262		
Options exercised	(187,953)	$ 23.943		
Options forfeited	(349,740)	$ 35.326		
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**

The weighted average fair values of options granted during 2000, 1999 and 1998 were $28.73, $12.80 and $13.44, 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 2000, 1999 and 1998, respectively: risk-free interest rates of 5.5%, 6.0% and 5.0%; dividend yields of 0.4%, 0.5% and 0.4%; expected lives of 5, 5 and 5 years; and volatility of the price of the underlying common stock of 40.0%, 35.2% and 31.7%.

The following table summarizes information about Devon's stock options which were outstanding, and those which were exercisable, as of December 31, 2000:

	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	886,899	2.98 Years	$22.732	881,065	$22.719
$28.830-$33.381	1,892,214	6.52 Years	$30.691	1,612,472	$30.705
$34.375-$39.773	1,288,365	6.10 Years	$36.550	1,263,100	$36.554
$40.125-$49.950	522,150	5.56 Years	$46.067	506,884	$46.017
$50.142-$59.813	2,146,853	7.75 Years	$53.072	1,155,202	$54.212
$60.150-$89.660	619,473	4.84 Years	$71.797	606,073	$72.050
	7,355,954	6.17 Years	$41.843	6,024,796	$40.718

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 2000, 1999 and 1998 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,		2000	1999	1998
	(IN THOUSANDS, EXCEPTPER SHARE AMOUNTS)			
Net earnings (loss) available to common shareholders:				
As reported	$	**720,607**	(157,795)	(235,885)
Pro forma	$	**701,852**	(173,005)	(252,070)
Net earnings (loss) per share available to common shareholders:				
As reported:				
Basic	$	**5.66**	(1.68)	(3.32)
Diluted	$	**5.50**	(1.68)	(3.32)
Pro forma:				
Basic	$	**5.51**	(1.85)	(3.55)
Diluted	$	**5.36**	(1.85)	(3.55)

Share Rights Plan

Under Devon's share 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, 2000, 1999 and 1998.

(IN THOUSANDS)		2000 CARRYING AMOUNT	2000 FAIR VALUE	1999 CARRYING AMOUNT	1999 FAIR VALUE	1998 CARRYING AMOUNT	1998 FAIR VALUE
Investments	$	**606,117**	**606,117**	634,281	634,281	1,930	1,930
Oil and gas price hedge agreements	$	**—**	**(57,560)**	—	(9,540)	—	1,988
Foreign exchange hedge agreements	$	**—**	**(533)**	—	(2,535)	—	(9,310)
Long-term debt (including current portion)	$	**(2,048,836)**	**(2,049,779)**	(2,416,521)	(2,400,334)	(735,871)	(758,075)
TCP Securities	$	**—**	**—**	—	—	(149,500)	(171,400)

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, 2000, 1999 and 1998.

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.

Foreign Exchange Hedge Agreements - The fair values of the foreign exchange agreements 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.

TCP Securities - The fair values of the TCP securities are based on quoted market prices provided by brokers.

The following table covers Devon's notional volumes and pricing on open natural gas hedging instruments as of December 31, 2000:

YEAR OF PRODUCTION		2001	2002
Volumes (billion British thermal units)		14,027	3,333
Average price to be received	$	2.18	2.52

The floating reference prices which Devon will pay the counterparties to the above gas price hedging instruments include several index prices based upon the area of the gas production that is hedged. For the hedged Canadian gas production, these reference prices are primarily based on index prices published by the Alberta Energy Company ("AECO"). For the hedged U.S. production, the reference prices are primarily based on index prices published by "Inside F.E.R.C.'s Gas Market Report" ("Inside FERC") for the Rocky Mountains.

In addition to the above gas hedging instruments, Devon also had a natural gas basis swap in effect as of December 31, 2000. In this basis swap, which covers 20,000 MMBtus per day, Devon owes the counterparty the applicable monthly Colorado Interstate Gas Co. index price as published by Inside FERC, while the counterparty owes Devon the average NYMEX price for the last three settlement days of the month less $0.30 per MMBtu. The net difference is settled by the parties each month. This basis swap continues through August 31, 2004.

Devon has certain foreign currency hedging instruments that offset a portion of the exposure to currency fluctuations on Canadian oil sales that are based on U.S. dollar prices. Gains and losses recognized on these foreign currency hedging instruments are included as increases or decreases to realized oil sales. As of December 31, 2000, Devon had open foreign currency hedging instruments in which it will sell $10 million in 2001 at average Canadian-to-U.S. dollar exchange rates of $0.7102. Under this agreement, Devon will buy the same amount of dollars at the floating exchange rate.

Devon's 1999 and 1998 consolidated balance sheets include deferred revenues of $0.4 million and $1.0 million, respectively, for gains realized on the early termination of commodity and foreign currency hedging instruments in prior years.

12. RETIREMENT PLANS

Devon has non-contributory defined benefit retirement plans (the "Basic Plans") which include U.S. 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, 2000, 1999 and 1998.

	PENSION BENEFITS			OTHER POSTRETIREMENT BENEFITS		
	2000	1999	1998	2000	1999	1998
	(IN THOUSANDS)					
Change in benefit obligation:						
Benefit obligation at beginning of year	**$ 155,569**	63,841	53,859	**$ 37,860**	8,100	6,600
Service cost	**6,736**	4,937	2,685	**809**	838	400
Interest cost	**11,283**	6,464	4,035	**2,330**	1,249	500
Participant contributions	**—**	—	—	**147**	—	100
Amendments	**4,303**	—	293	**(1,985)**	—	—
Mergers and acquisitions	**—**	87,751	—	**—**	28,659	—
Curtailment gain	**(3,037)**	—	—	**(346)**	—	—
Actuarial (gain) loss	**(2,963)**	(3,525)	5,573	**(3,153)**	600	1,000
Benefits paid	**(7,290)**	(3,899)	(2,604)	**(3,520)**	(1,586)	(500)
Benefit obligation at end of year	**164,601**	155,569	63,841	**32,142**	37,860	8,100
Change in plan assets:						
Fair value of plan assets at beginning of year	**157,894**	41,531	43,136	**—**	—	—
Actual return on plan assets	**2,574**	14,808	113	**—**	—	—
PennzEnergy merger	**—**	104,181	—	**—**	—	—
Employer contributions	**1,664**	1,273	886	**3,373**	1,486	400
Participant contributions	**—**	—	—	**147**	100	100
Benefits paid	**(7,290)**	(3,899)	(2,604)	**(3,520)**	(1,586)	(500)
Fair value of plan assets at end of year	**154,842**	157,894	41,531	**—**	—	—
Funded status	**(9,759)**	2,325	(22,310)	**(32,142)**	(37,860)	(8,100)
Unrecognized net actuarial (gain) loss	**9,888**	(2,723)	9,130	**(2,199)**	800	200
Unrecognized prior service cost	**1,570**	1,966	2,322	**(1,201)**	—	—
Unrecognized net transition (asset) obligation	**(6,331)**	(400)	(500)	**1,152**	2,100	2,300
Other	**—**	100	—	**—**	100	100
Net amount recognized	**$ (4,632)**	1,268	(11,358)	**$ (34,390)**	(34,860)	(5,500)
The net amounts recognized in the consolidated balance sheets consist of:						
(Accrued) prepaid benefit cost	**$ (4,632)**	1,268	(11,358)	**$ (34,390)**	(34,860)	(5,500)
Additional minimum liability	**(735)**	(3,110)	(2,987)	**—**	—	—
Intangible asset	**508**	1,537	1,808	**—**	—	—
Accumulated other comprehensive loss	**227**	1,573	1,179	**—**	—	—
Net amount recognized	**$ (4,632)**	1,268	(11,358)	**$ (34,390)**	(34,860)	(5,500)
Assumptions:						
Discount rate	**7.65%**	7.34%	6.69%	**7.65%**	7.32%	6.75%
Expected return on plan assets	**8.50%**	8.37%	9.35%	**N/A**	N/A	N/A
Rate of compensation increase	**5.00%**	4.88%	4.84%	**5.00%**	4.75%	4.75%

The benefit obligation for the defined benefit pension plans with benefit obligations in excess of assets was $87.0 million as of December 31, 2000. The plan assets for these plans at December 31, 2000 totaled $49.9 million.

Net periodic benefit cost included the following components:

	Pension Benefits			Other Postretirement Benefits		
	2000	1999	1998	2000	1999	1998
	(In thousands)					
Service cost	**$ 6,736**	4,937	2,685	**$ 809**	838	400
Interest cost	**11,283**	6,464	4,035	**2,330**	1,249	500
Expected return on plan assets	**(13,247)**	(6,900)	(3,932)	**—**	—	—
Amortization of prior service cost	**289**	256	256	**(37)**	—	—
Amortization of transition obligation	**(52)**	—	—	**170**	200	200
Recognized net actuarial (gain) loss	**294**	320	11	**(207)**	—	—
Net periodic benefit cost	**$ 5,303**	5,077	3,055	**$ 3,065**	2,287	1,100

For measurement purposes, a 10% annual rate of increase in the per capita cost of covered health care benefits was assumed in 2000. 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 thousands)	
Effect on total of service and interest cost components for 2000	$ 230	$ (204)
Effect on year-end 2000 postretirement benefit obligation	$ 1,062	$ (1,009)

Devon has incurred certain postemployment benefits to former or inactive employees who are not retirees. These benefits include salary continuance, severance and disability health care and life insurance which are accounted for under SFAS No. 112, “Employer’s Accounting for Postemployment Benefits.” The accrued postemployment benefit liability was approximately $12.7 million and $2.5 million at the end of 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 $5.0 million, $4.3 million and $2.3 million for the years ended December 31, 2000, 1999 and 1998, 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 2000, 1999 and 1998, Devon’s combined contributions to the Canadian defined contribution plan and the Canadian savings plan were $2.1 million, $1.9 million and $1.8 million, respectively.

As a result of the Santa Fe Snyder merger, Devon also has a savings plan with respect to certain personnel employed in foreign locations. The plan is an unsecured creditor of Devon and at December 31, 2000, 1999 and 1998, Devon’s liability with respect to the plan totaled $0.4 million, $0.4 million and $0.3 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.

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 CERCLAor similar state legislation with respect to various waste disposal areas owned or operated by third parties. As of December 31, 2000, Devon's consolidated balance sheet included $7.8 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

More than 30 oil companies, including Devon, are involved in disputes in which it is alleged that such companies and related parties underpaid royalty, overriding royalty and working interests owners in connection with the production of crude oil. The proceedings include suits in federal court in Texas, Louisiana, Mississippi and Wyoming that have been consolidated into one proceeding in Texas. To avoid expensive and protracted litigation, certain parties, including Devon, have entered into a global settlement agreement which provides for a settlement of all claims of all members of the settlement class. The court held a fairness hearing and issued an Amended Final Judgment approving the settlement on September 10, 1999. However, certain entities have appealed their objections to the settlement.

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

Maersk Rig Contract

In December 1997, the working interest owner partner of Pennzoil Venezuela Corporation, S.A. ("PVC"), a subsidiary of Devon as a result of the PennzEnergy merger, entered into a contract with Maersk Jupiter Drilling, S.A. ("Maersk") for the provision of a rig for drilling services relative to the anticipated drilling program associated with Devon's Block 70/80 in Lake Maracaibo, Venezuela. The rig was assembled and delivered by Maersk to Lake Maracaibo where it performed an abbreviated drilling program for both Blocks 68/79 and 70/80. It is currently stacked in Lake Maracaibo. The contract, which expires October 1, 2001, provides for early termination, with a charge for such termination which is currently estimated at $42,000 per day with certain escalation factors for the balance of the term. As of December 31, 2000, Devon's consolidated balance sheet included accrued liabilities, reflected in "Other liabilities," for the expected cost to terminate/settle the contract. Devon does not currently believe there is a reasonable possibility of incurring additional material costs in excess of the liability recognized for such termination/settlement of the contract.

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, 2000:

YEAR ENDING DECEMBER 31,	(IN THOUSANDS)
2001	$ 14,394
2002	12,279
2003	11,513
2004	10,779
2005	10,293
Thereafter	20,466
Total minimum lease payments required	$ 79,724

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

	(IN THOUSANDS)
2000	**$ 18,564**
1999	$ 24,204
1998	$ 18,319

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 to the extent that it needs such payments to distribute $0.39 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 $19.4 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 2000, the Trust had received support payments totaling $4.2 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, 2000 and 1999, accounts payable as shown on the accompanying consolidated balance sheets included $4.1 million and $3.4 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. 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 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 1999 and 1998, Devon reduced the carrying value of its oil and gas properties by $476.1 million and $422.5 million, respectively, due to the full cost ceiling limitations. The after-tax effect of these reductions in 1999 and 1998 were $309.7 million and $280.8 million, respectively.

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,		2000	1999	1998
			(IN THOUSANDS)	
Property acquisition costs:				
Proved, excluding deferred income taxes	$	**291,355**	3,002,269	245,467
Deferred income taxes		**—**	131,700	21,382
Total proved, including deferred income taxes	$	**291,355**	3,133,969	266,849
Unproved, excluding deferred income taxes:				
Business combinations		**—**	83,505	5,278
Other acquisitions		**55,344**	40,583	55,827
Deferred income taxes		**—**	—	661
Total unproved, including deferred income taxes	$	**55,344**	124,088	61,766
Exploration costs	$	**212,719**	157,706	176,014
Development costs	$	**636,379**	336,126	294,105

DOMESTIC

YEAR ENDED DECEMBER 31,		2000	1999	1998
			(IN THOUSANDS)	
Property acquisition costs:				
Proved, excluding deferred income taxes	$	**177,072**	2,670,237	87,549
Deferred income taxes		**—**	131,700	—
Total proved, including deferred income taxes	$	**177,072**	2,801,937	87,549
Unproved, excluding deferred income taxes:				
Business combinations		**—**	81,755	—
Other acquisitions		**34,805**	27,728	40,364
Deferred income taxes		**—**	—	—
Total unproved, including deferred income taxes	$	**34,805**	109,483	40,364
Exploration costs	$	**117,119**	88,171	71,486
Development costs	$	**466,090**	228,095	149,286

CANADA

YEAR ENDED DECEMBER 31,		2000	1999	1998
			(IN THOUSANDS)	
Property acquisition costs:				
Proved, excluding deferred income taxes	$	**69,736**	29,532	107,818
Deferred income taxes		**—**	—	21,382
Total proved, including deferred income taxes	$	**69,736**	29,532	129,200
Unproved, excluding deferred income taxes:				
Business combinations		**—**	—	5,278
Other acquisitions		**16,977**	9,155	10,263
Deferred income taxes		**—**	—	661
Total unproved, including deferred income taxes	$	**16,977**	9,155	16,202
Exploration costs	$	**54,769**	37,197	49,928
Development costs	$	**56,654**	29,811	75,119

INTERNATIONAL

YEAR ENDED DECEMBER 31,		2000	1999	1998
		(IN THOUSANDS, EXCEPT PER EQUIVALENT BARREL AMOUNTS)		
Property acquisition costs:				
Proved, excluding deferred income taxes	$	**44,547**	302,500	50,100
Deferred income taxes		**—**	—	—
Total proved, including deferred income taxes	$	**44,547**	302,500	50,100
Unproved, excluding deferred income taxes:				
Business combinations		**—**	1,750	—
Other acquisitions		**3,562**	3,700	5,200
Deferred income taxes		**—**	—	—
Total unproved, including deferred income taxes	$	**3,562**	5,450	5,200
Exploration costs	$	**40,831**	32,338	54,600
Development costs	$	**113,635**	78,220	69,700

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 $61.8 million, $28.9 million and $14.8 million in the years 2000, 1999 and 1998, respectively.

Due to the tax-free nature of the merger between Santa Fe and Snyder in May 1999, additional deferred tax liabilities of $131.7 million were allocated to proved properties. Due to the tax-free nature of the PennzEnergy merger in August 1999, additional deferred tax liabilities of $346.9 million were recorded in 1999 and allocated to goodwill.

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,		2000	1999	1998
		(IN THOUSANDS, EXCEPT PER EQUIVALENT BARREL AMOUNTS)		
Oil, gas and natural gas liquids sales	$	**2,718,445**	1,256,872	681,978
Production and operating expenses		**(597,333)**	(377,472)	(274,618)
Depreciation, depletion and amortization		**(662,890)**	(390,117)	(230,419)
Amortization of goodwill		**(41,332)**	(16,111)	—
Reduction of carrying value of oil and gas properties		**—**	(476,100)	(422,500)
Income tax (expense) benefit		**(571,755)**	(24,984)	65,515
Results of operations for oil and gas producing activities	$	**845,135**	(27,912)	(180,044)
Depreciation, depletion and amortization per equivalent barrel of production	$	**5.48**	4.46	3.74

DOMESTIC

YEAR ENDED DECEMBER 31,		2000	1999	1998
	(IN THOUSANDS, EXCEPT PER EQUIVALENT BARREL AMOUNTS)			
Oil, gas and natural gas liquids sales	$	**2,167,571**	891,670	417,313
Production and operating expenses		**(462,849)**	(254,077)	(164,612)
Depreciation, depletion and amortization		**(541,174)**	(293,841)	(154,127)
Amortization of goodwill		**(41,303)**	(16,106)	—
Reduction of carrying value of oil and gas properties		**—**	(463,700)	(301,400)
Income tax (expense) benefit		**(445,783)**	37,786	63,630
Results of operations for oil and gas producing activities	$	**676,462**	(98,268)	(139,196)
Depreciation, depletion and amortization per equivalent barrel of production	$	**5.73**	4.98	4.41

CANADA

YEAR ENDED DECEMBER 31,		2000	1999	1998
	(IN THOUSANDS, EXCEPT PER EQUIVALENT BARREL AMOUNTS)			
Oil, gas and natural gas liquids sales	$	**303,537**	204,501	169,965
Production and operating expenses		**(64,773)**	(62,595)	(58,506)
Depreciation, depletion and amortization		**(64,094)**	(64,514)	(43,392)
Reduction of carrying value of oil and gas properties		**—**	—	—
Income tax (expense) benefit		**(79,363)**	(37,736)	(37,615)
Results of operations for oil and gas producing activities	$	**95,307**	39,656	30,452
Depreciation, depletion and amortization per equivalent barrel of production	$	**4.05**	3.56	2.41

INTERNATIONAL

YEAR ENDED DECEMBER 31,		2000	1999	1998
	(IN THOUSANDS, EXCEPT PER EQUIVALENT BARREL AMOUNTS)			
Oil, gas and natural gas liquids sales	$	**247,337**	160,701	94,700
Production and operating expenses		**(69,711)**	(60,800)	(51,500)
Depreciation, depletion and amortization		**(57,622)**	(31,762)	(32,900)
Amortization of goodwill		**(29)**	(5)	—
Reduction of carrying value of oil and gas properties		**—**	(12,400)	(121,100)
Income tax (expense) benefit		**(46,609)**	(25,034)	39,500
Results of operations for oil and gas producing activities	$	**73,366**	30,700	(71,300)
Depreciation, depletion and amortization per equivalent barrel of production	$	**5.38**	3.06	3.78

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, 2000. Approximately 80%, 98% and 96%, of the respective year-end 2000, 1999 and 1998 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. All of the year-end 2000 and 1999 Canadian proved reserves were calculated by the independent petroleum consultants Paddock Lindstrom & Associates. All of the year-end 1998 Canadian proved reserves were calculated by the independent petroleum consultants of Paddock Lindstrom & Associates and AMH Group Ltd. All of the international proved reserves other than Canada as of December 31, 2000 and 1999 were calculated by the independent petroleum consultants of Ryder-Scott Company Petroleum Consultants. Of the 1998 international reserves other than Canada, 87% were calculated by Ryder-Scott Company Petroleum Consultants and 13% were based on Devon’s own estimates.

TOTAL	OIL (MBBLS)	GAS (MMCF)	NATURAL GAS LIQUIDS (MBBLS)
Proved reserves as of December 31, 1997	218,741	1,403,204	24,478
Revisions of estimates	(9,452)	(53,209)	2,391
Extensions and discoveries	27,497	174,527	8,652
Purchase of reserves	30,283	164,429	518
Production	(25,628)	(198,051)	(3,054)
Sale of reserves	(5,984)	(13,906)	(306)
Proved reserves as of December 31, 1998	235,457	1,476,994	32,679
Revisions of estimates	12,367	6,888	3,254
Extensions and discoveries	12,809	406,157	4,342
Purchase of reserves	272,412	1,417,747	32,795
Production	(31,756)	(304,203)	(5,111)
Sale of reserves	(4,572)	(53,956)	(142)
Proved reserves as of December 31, 1999	496,717	2,949,627	67,817
Revisions of estimates	(4,135)	99,223	3,312
Extensions and discoveries	33,939	601,317	6,041
Purchase of reserves	24,145	301,144	33
Production	(42,561)	(426,146)	(7,400)
Sale of reserves	(48,861)	(66,981)	(8,046)
Proved reserves as of December 31, 2000	**459,244**	**3,458,184**	**61,757**
Proved developed reserves as of:			
December 31, 1997	187,758	1,204,874	21,832
December 31, 1998	179,746	1,282,447	19,381
December 31, 1999	301,149	2,500,985	52,102
December 31, 2000	**261,432**	**2,631,267**	**46,256**

DOMESTIC	OIL (MBBLS)	GAS (MMCF)	NATURAL GAS LIQUIDS (MBBLS)
Proved reserves as of December 31, 1997	128,402	784,124	18,172
Revisions of estimates	(19,849)	10,919	219
Extensions and discoveries	3,042	108,308	371
Purchase of reserves	1,813	58,655	—
Production	(12,257)	(121,419)	(2,468)
Sale of reserves	—	(2,300)	—
Proved reserves as of December 31, 1998	101,151	838,287	16,294
Revisions of estimates	23,986	35,751	3,407
Extensions and discoveries	1,890	230,059	2,794
Purchase of reserves	142,908	1,399,634	32,709
Production	(17,822)	(221,061)	(4,396)
Sale of reserves	(2,689)	(8,284)	(4)
Proved reserves as of December 31, 1999	249,424	2,274,386	50,804
Revisions of estimates	(3,196)	100,844	4,296
Extensions and discoveries	20,430	504,977	5,092
Purchase of reserves	20,418	52,929	9
Production	(28,562)	(355,087)	(6,702)
Sale of reserves	(32,977)	(56,742)	(7,981)
Proved reserves as of December 31, 2000	**225,537**	**2,521,307**	**45,518**
Proved developed reserves as of:			
December 31, 1997	115,559	646,882	16,789
December 31, 1998	92,931	663,864	14,777
December 31, 1999	214,267	1,959,531	48,237
December 31, 2000	**192,190**	**2,087,287**	**42,155**

CANADA	OIL (MBBLS)	GAS (MMCF)	NATURAL GAS LIQUIDS (MBBLS)
Proved reserves as of December 31, 1997	36,139	582,780	5,106
Revisions of estimates	6,283	(70,402)	(248)
Extensions and discoveries	655	62,519	81
Purchase of reserves	8,170	105,774	518
Production	(6,257)	(67,158)	(566)
Sale of reserves	(5,984)	(11,606)	(306)
Proved reserves as of December 31, 1998	39,006	601,907	4,585
Revisions of estimates	(2,828)	(41,044)	(268)
Extensions and discoveries	219	52,698	448
Purchase of reserves	2,796	11,890	86
Production	(5,178)	(73,561)	(700)
Sale of reserves	(1,883)	(45,672)	(138)
Proved reserves as of December 31, 1999	32,132	506,218	4,013
Revisions of estimates	2,872	(5,854)	343
Extensions and discoveries	2,787	64,566	571
Purchase of reserves	3,597	27,224	24
Production	(4,760)	(62,284)	(682)
Sale of reserves	(136)	(6,361)	(65)
Proved reserves as of December 31, 2000	**36,492**	**523,509**	**4,204**
Proved developed reserves as of			
December 31, 1997	35,199	522,292	5,043
December 31, 1998	33,215	583,583	4,504
December 31, 1999	29,268	501,376	3,865
December 31, 2000	**29,721**	**507,703**	**4,072**

INTERNATIONAL	OIL (MBBLS)	GAS (MMCF)	NATURAL GAS LIQUIDS (MBBLS)
Proved reserves as of December 31, 1997	54,200	36,300	1,200
Revisions of estimates	4,114	6,274	2,420
Extensions and discoveries	23,800	3,700	8,200
Purchase of reserves	20,300	—	—
Production	(7,114)	(9,474)	(20)
Sale of reserves	—	—	—
Proved reserves as of December 31, 1998	95,300	36,800	11,800
Revisions of estimates	(8,791)	12,181	115
Extensions and discoveries	10,700	123,400	1,100
Purchase of reserves	126,708	6,223	—
Production	(8,756)	(9,581)	(15)
Sale of reserves	—	—	—
Proved reserves as of December 31, 1999	215,161	169,023	13,000
Revisions of estimates	(3,811)	4,233	(1,327)
Extensions and discoveries	10,722	31,774	378
Purchase of reserves	130	220,991	—
Production	(9,239)	(8,775)	(16)
Sale of reserves	(15,748)	(3,878)	—
Proved reserves as of December 31, 2000	**197,215**	**413,368**	**12,035**
Proved developed reserves as of			
December 31, 1997	37,000	35,700	—
December 31, 1998	53,600	35,000	100
December 31, 1999	57,614	40 078	—
December 31, 2000	**39,521**	**36,277**	**29**

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,	2000	1999	1998
		(IN THOUSANDS)	
Future cash inflows	**$ 40,594,130**	18,494,929	5,114,485
Future costs:			
Development	**(1,634,888)**	(1,506,678)	(495,977)
Production	**(8,198,640)**	(6,270,893)	(2,091,688)
Future income tax expense	**(9,087,923)**	(1,928,398)	(196,475)
Future net cash flows	**21,672,679**	8,788,960	2,330,345
10% discount to reflect timing of cash flows	**(9,200,492)**	(4,020,526)	(916,757)
Standardized measure of discounted future net cash flows	**$ 12,472,187**	4,768,434	1,413,588

DOMESTIC

DECEMBER 31,	2000	1999	1998
		(IN THOUSANDS)	
Future cash inflows	**$ 29,143,762**	11,362,918	2,718,030
Future costs:			
Development	**(915,969)**	(750,497)	(162,715)
Production	**(5,660,966)**	(3,894,271)	(1,123,932)
Future income tax expense	**(6,345,941)**	(1,071,699)	(117,912)
Future net cash flows	**16,220,886**	5,646,451	1,313,471
10% discount to reflect timing of cash flows	**(6,591,538)**	(2,335,312)	(503,689)
Standardized measure of discounted future net cash flows	**$ 9,629,348**	3,311,139	809,782

CANADA

DECEMBER 31,	2000	1999	1998
		(IN THOUSANDS)	
Future cash inflows	**$ 5,686,629**	1,666,358	1,333,655
Future costs:			
Development	**(84,492)**	(66,631)	(85,362)
Production	**(616,605)**	(514,825)	(491,256)
Future income tax expense	**(1,967,441)**	(204,290)	(39,563)
Future net cash flows	**3,018,091**	880,612	717,474
10% discount to reflect timing of cash flows	**(1,240,934)**	(320,722)	(279,568)
Standardized measure of discounted future net cash flows	**$ 1,777,157**	559,890	437,906

INTERNATIONAL

DECEMBER 31,	2000	1999	1998
		(IN THOUSANDS)	
Future cash inflows	**$ 5,763,739**	5,465,653	1,062,800
Future costs:			
Development	**(634,427)**	(689,550)	(247,900)
Production	**(1,921,069)**	(1,861,797)	(476,500)
Future income tax expense	**(774,541)**	(652,409)	(39,000)
Future net cash flows	**2,433,702**	2,261,897	299,400
10% discount to reflect timing of cash flows	**(1,368,020)**	(1,364,492)	(133,500)
Standardized measure of discounted future net cash flows	**$ 1,065,682**	897,405	165,900

Future cash inflows are computed by applying year-end prices (averaging $23.77 per barrel of oil, adjusted for transportation and other charges, $8.04 per Mcf of gas and $29.80 per barrel of natural gas liquids at December 31, 2000) 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. Subsequent to December 31, 2000, the price of natural gas declined. The average price in February 2001 for gas sold at market sensitive prices in North America was approximately one-third below the year-end 2000 price.

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.

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,	2000	1999	1998
		(IN THOUSANDS)	
Beginning balance	**$ 4,768,434**	1,413,588	1,680,676
Sales of oil, gas and natural gas liquids, net of production costs	**(2,010,675)**	(879,400)	(407,360)
Net changes in prices and production costs	**9,753,295**	1,737,640	(743,193)
Extensions, discoveries, and improved recovery, net of future development costs	**2,742,182**	315,932	280,414
Purchase of reserves, net of future development costs	**618,134**	2,881,881	223,055
Development costs incurred during the period which reduced future development costs	**182,533**	233,880	284,999
Revisions of quantity estimates	**420,250**	(62,821)	(181,314)
Sales of reserves in place	**(818,602)**	(77,707)	(36,565)
Accretion of discount	**581,172**	146,904	201,465
Net change in income taxes	**(4,221,575)**	(929,237)	305,317
Other, primarily changes in timing	**457,039**	(12,226)	(193,906)
Ending balance	**$ 12,472,187**	4,768,434	1,413,588

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.

Following is certain financial information regarding Devon's segments for 2000, 1999 and 1998. The revenues reported are all from external customers.

	U.S.	CANADA	INTERNATIONAL	TOTAL
		(IN THOUSANDS)		
AS OF DECEMBER 31, 2000:				
Current assets	$ 644,685	79,372	210,080	934,137
Property and equipment, net of accumulated depreciation, depletion and amortization	3,639,673	585,517	684,346	4,909,536
Other assets	964,934	89	51,782	1,016,805
Total assets	$ 5,249,292	664,978	946,208	6,860,478
Current liabilities	448,994	74,154	105,839	628,987
Long-term debt	1,902,184	146,652	—	2,048,836
Deferred tax liabilities (assets)	536,935	68,578	21,313	626,826
Other liabilities	258,812	1,831	17,582	278,225
Stockholders'equity	2,102,367	373,763	801,474	3,277,604
Total liabilities and stockholders'equity	$ 5,249,292	664,978	946,208	6,860,478
YEAR ENDED DECEMBER 31, 2000:				
REVENUES				
Oil sales	$ 726,897	116,427	235,435	1,078,759
Gas sales	1,304,626	169,032	11,563	1,485,221
Natural gas liquids sales	136,048	18,078	339	154,465
Other	58,569	4,984	2,105	65,658
Total revenues	2,226,140	308,521	249,442	2,784,103
COSTS AND EXPENSES				
Lease operating expenses	319,154	52,340	69,286	440,780
Transportation costs	41,956	11,353	—	53,309
Production taxes	101,739	1,080	425	103,244
Depreciation, depletion and amortization of property and equipment	565,633	64,735	62,972	693,340
Amortization of goodwill	41,303	—	29	41,332
General and administrative expenses	80,358	10,380	2,270	93,008
Expenses related to mergers	60,373	—	—	60,373
Interest expense	143,169	10,140	1,020	154,329
Deferred effect of changes in foreign currency exchange rate on subsidiary's long-term debt	—	2,408	—	2,408
Total costs and expenses	1,353,685	152,436	136,002	1,642,123
Earnings before income tax expense	872,455	156,085	113,440	1,141,980
INCOME TAX EXPENSE				
Current	112,757	2,268	15,768	130,793
Deferred	185,231	67,318	28,296	280,845
Total income tax expense	297,988	69,586	44,064	411,638
Net earnings	$ 574,467	86,499	69,376	730,342
Capital expenditures	$ 893,087	202,673	184,372	1,280,132

17. SEGMENT INFORMATION (CONTINUED)

		U.S.	CANADA	INTERNATIONAL	TOTAL
		(IN THOUSANDS)			
AS OF DECEMBER 31, 1999:					
Current assets	$	391,328	69,279	129,687	590,294
Property and equipment, net of accumulated depreciation, depletion and amortization		3,424,415	467,465	531,540	4,423,420
Other assets		944,958	98	137,590	1,082,646
Total assets	$	4,760,701	536,842	798,817	6,096,360
Current liabilities		356,944	44,989	65,411	467,344
Long-term debt		2,077,180	339,341	—	2,416,521
Deferred tax liabilities (assets)		340,514	1,733	(18,182)	324,065
Other liabilities		317,706	3,098	46,306	367,110
Stockholders' equity		1,668,357	147,681	705,282	2,521,320
Total liabilities and stockholders' equity	$	4,760,701	536,842	798,817	6,096,360
YEAR ENDED DECEMBER 31, 1999:					
REVENUES					
Oil sales	$	332,219	80,298	148,501	561,018
Gas sales		501,841	114,128	11,900	627,869
Natural gas liquids sales		57,610	10,075	300	67,985
Other		14,574	4,652	1,370	20,596
Total revenues		906,244	209,153	162,071	1,277,468
COSTS AND EXPENSES					
Lease operating expenses		188,576	49,831	60,400	298,807
Transportation costs		22,524	11,401	—	33,925
Production taxes		42,977	1,363	400	44,740
Depreciation, depletion and amortization of property and equipment		309,292	65,176	31,907	406,375
Amortization of goodwill		16,106	—	5	16,111
General and administrative expenses		68,807	12,189	(351)	80,645
Expenses related to mergers		16,800	—	—	16,800
Interest expense		83,679	24,945	989	109,613
Deferred effect of changes in foreign currency exchange rate on subsidiary's long-term debt		—	(13,154)	—	(13,154)
Distributions on preferred securities of subsidiary trust		6,884	—	—	6,884
Reduction of carrying value of oil and gas properties		463,700	—	12,400	476,100
Total costs and expenses		1,219,345	151,751	105,750	1,476,846
Earnings (loss) before income tax expense (benefit) and extraordinary item		(313,101)	57,402	56,321	(199,378)
INCOME TAX EXPENSE (BENEFIT)					
Current		15,348	2,908	4,800	23,056
Deferred		(119,881)	26,654	20,737	(72,490)
Total income tax expense (benefit)		(104,533)	29,562	25,537	(49,434)
Net earnings (loss) before extraordinary item		(208,568)	27,840	30,784	(149,944)
Extraordinary loss		(4,200)	—	—	(4,200)
Net earnings (loss)	$	(212,768)	27,840	30,784	(154,144)
Capital expenditures	$	686,669	91,853	104,898	883,420

	U.S.	CANADA	INTERNATIONAL	TOTAL
		(IN THOUSANDS)		
AS OF DECEMBER 31, 1998:				
Current assets	$ 90,698	53,550	82,400	226,648
Property and equipment, net of accumulated depreciation, depletion and amortization	991,040	465,488	167,000	1,623,528
Deferred tax assets (liabilities)	(36,093)	24,174	66,300	54,381
Other assets	17,126	1,454	7,400	25,980
Total assets	$ 1,062,771	544,666	323,100	1,930,537
Current liabilities	119,132	55,624	45,100	219,856
Long-term debt	365,600	370,271	—	735,871
Other liabilities	67,487	5,760	2,300	75,547
TCP Securities	149,500	—	—	149,500
Stockholders’equity	361,052	113,011	275,700	749,763
Total liabilities and stockholders’equity	$ 1,062,771	544,666	323,100	1,930,537
YEAR ENDED DECEMBER 31, 1998:				
REVENUES				
Oil sales	$ 152,297	75,493	82,200	309,990
Gas sales	245,145	89,828	12,300	347,273
Natural gas liquids sales	19,871	4,644	200	24,715
Other	9,294	13,754	1,200	24,248
Total revenues	426,607	183,719	95,900	706,226
COSTS AND EXPENSES				
Lease operating expenses	127,451	47,910	51,200	226,561
Transportation costs	14,251	8,935	—	23,186
Production taxes	22,910	1,661	300	24,871
Depreciation, depletion and amortization of property and equipment	165,654	44,590	32,900	243,144
General and administrative expenses	35,752	12,502	(2,800)	45,454
Expenses related to mergers	3,064	10,085	—	13,149
Interest expense	20,558	21,974	1,000	43,532
Deferred effect of changes in foreign currency exchange rate on subsidiary’s long-term debt	—	16,104	—	16,104
Distributions on preferred securities of subsidiary trust	9,717	—	—	9,717
Reduction of carrying value of oil and gas properties	301,400	—	121,100	422,500
Total costs and expenses	700,757	163,761	203,700	1,068,218
Earnings (loss) before income tax expense (benefit)	(274,150)	19,958	(107,800)	(361,992)
INCOME TAX EXPENSE (BENEFIT)				
Current	(7,588)	1,975	1,900	(3,713)
Deferred	(92,360)	11,166	(41,200)	(122,394)
Total income tax expense (benefit)	(99,948)	13,141	(39,300)	(126,107)
Net earnings (loss)	$ (174,202)	6,817	(68,500)	(235,885)
Capital expenditures	$ 347,634	205,178	160,000	712,812

18. SUPPLEMENTAL QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Following is a summary of the unaudited interim results of operations for the years ended December 31, 2000 and 1999.

2000		FIRST QUARTER	SECOND QUARTER	THIRD QUARTER	FOURTH QUARTER	FULL YEAR
(IN THOUSANDS, EXCEPTPER SHARE AMOUNTS)						
Oil, gas and natural gas liquids sales	$	548,351	635,777	695,475	838,842	2,718,445
Total revenues	$	560,416	648,484	725,141	850,062	2,784,103
Net earnings (loss)	$	105,187	153,334	164,912	306,909	730,342
Net earnings (loss) 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

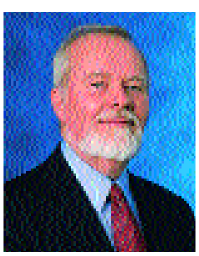
1999		FIRST QUARTER	SECOND QUARTER	THIRD QUARTER	FOURTH QUARTER	FULL YEAR
(IN THOUSANDS, EXCEPTPER SHARE AMOUNTS)						
Oil, gas and natural gas liquids sales	$	159,632	221,129	380,562	495,549	1,256,872
Total revenues	$	162,205	224,048	385,972	505,243	1,277,468
Net earnings (loss)	$	6,580	(286,491)	50,852	74,915	(154,144)
Net earnings (loss) per common share:						
Basic	$	0.09	(3.55)	0.50	0.59	(1.68)
Diluted	$	0.09	(3.55)	0.48	0.57	(1.68)

The third and fourth quarters of 2000 include $57.2 million and $3.2 million, respectively, of expenses incurred in connection with the Santa Fe Snyder merger. The after-tax effect of these expenses was $35.3 million and $1.9 million, respectively. The per share effect of these quarterly reductions was $0.28 and $0.01, respectively.

The second and fourth quarters of 1999 include pre-tax reductions of the carrying value of oil and gas properties of $463.8 million and $12.3 million, respectively. The after-tax effects of these quarterly reductions were $301.7 million and $8.0 million, respectively. The per share effect of these quarterly reductions were $3.74 and $0.06, respectively. The second quarter of 1999 includes $16.8 million of expenses incurred in connection with the Snyder merger. The after-tax effect of these expenses was $10.9 million, or $0.14 per share.

John W. Nichols, 86, a co-founder of Devon, was named Chairman Emeritus in 1999. He 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 developed the conventional reserves in the Northeast Blanco Unit of the San Juan Basin. Mr. Nichols is a non-practicing Certified Public Accountant.

J. Larry Nichols, 58, is a co-founder of Devon. He was named Chairman of the Board of Directors in 2000. He has been a Director since 1971, President since 1976 and Chief Executive Officer since 1980. Mr. Nichols serves as Vice President of the Independent Petroleum Association of America, Vice Chairman of the Natural Gas Supply Association and President of the Oklahoma Nature Conservancy. In addition, Mr. Nichols is a Director of the Domestic Petroleum Council, the Independent Petroleum Association of New Mexico, the Oklahoma Independent Petroleum Association and the National Petroleum Council. Mr. Nichols serves on the Board of Governors of the American Stock Exchange. He also serves as a Director of New York Stock Exchange listed companies Smedvig asa and CMI Corporation. Mr. Nichols holds a geology degree from Princeton University and a law degree from the University of Michigan. He served as a law clerk to Mr. Chief Justice Earl Warren and Mr. Justice Tom Clark of the U.S. Supreme Court.

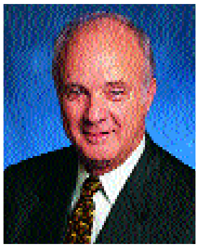


Thomas F. Ferguson, 64, has been a Director of Devon since 1982 and is the Chairman of the Audit Committee. He is the Managing Director of United Gulf Management Ltd., a wholly owned subsidiary of Kuwait Investment Projects Company KSC. Mr. Ferguson represents United Gulf Management Ltd. on the boards of various companies in which it invests, including Baltic Transit Bank in Latvia and Tunis International Bank in Tunisia. Mr. Ferguson is a Canadian qualified Certified General Accountant and was formerly employed by the Economist Intelligence Unit of London as a financial consultant.

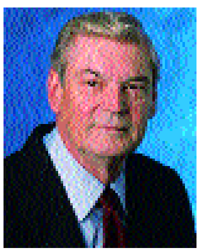
David M. Gavrin, 66, has been a Director of Devon since 1979, and serves as the Chairman of the Compensation and Stock Option Committee. He is a Director of United American Energy Corp., an independent power producer, and MetBank Holding Corporation. For 11 years prior to 1990 he was a General Partner of Windcrest Partners and for 14 years prior to that he was an officer of Drexel Burnham Lambert Incorporated.

Michael E. Gellert, 69, has been a Director of Devon since 1971 and is a member of the Compensation and Stock Option Committee. Mr. Gellert is a General Partner of Windcrest Partners, a private investment partnership in New York City, having held that position since 1967. From January 1958 until his retirement in October 1989, Mr. 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, Mr. Gellert also serves on the boards of High Speed Access Corporation, Humana Inc., Six Flags Inc., Seacor Smit Inc. and Smith Barney World Funds. Mr. Gellert is also a member of the Putnam Trust Company Advisory Board to the Bank of New York.

William E. Greehey, 64, was elected to Devon's Board of Directors in 2000. Prior to that, he served as a Director of Santa Fe Snyder Corporation. He is Chairman of the Board, Chief Executive Officer and Director of Valero Energy Corporation (refining and marketing). He has been with Valero since 1963.

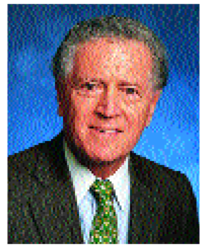


John A. Hill, 59, was elected to the Board of Directors in 2000. Prior to that, he served as a Director of Santa Fe Snyder Corporation. He is Vice Chairman and Managing Director of First Reserve Corporation, an oil and gas investment management company. Prior to joining First Reserve, Mr. Hill was President, 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. Mr. Hill is a Trustee of the Putnam Funds in Boston and a Director of TransMontaigne Inc. and various companies controlled by First Reserve Corporation.

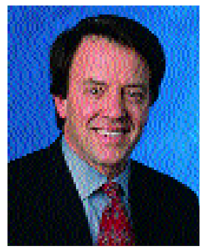


William J. Johnson, 66, was elected to the Board of Directors in 1999. Mr. Johnson is a private consultant for the oil and gas industry. He is President and a Director of JonLoc Inc., an oil and gas company of which he and his family are sole shareholders. He also serves as a Director of Tesoro Petroleum Corp. From 1991 to 1994, Mr. Johnson was President, Chief Operating Officer and a Director of Apache Corporation.

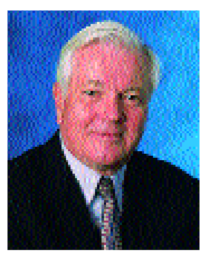
Michael M. Kanovsky, 52, was elected to the Board of Directors in 1998. Mr. Kanovsky has been on the Board of Directors of Northstar Energy Corporation, Devon's Canadian subsidiary, since 1982. Mr. Kanovsky is President of Sky Energy Corporation, a privately held energy corporation. He is a Director of ARC Resources Ltd., Bonavista Petroleum Corporation and Vanguard Oil Corporation. Mr. Kanovsky was Chairman of Taro Industries Ltd., Vice Chairman of Precision Drilling Inc. and a past Director of the Canadian Association of Oilwell Drilling Contractors. Mr. Kanovsky obtained his bachelor's degree in mechanical engineering from Queen's University in Kingston, Ontario, and his master's degree from the Ivey School of Business.



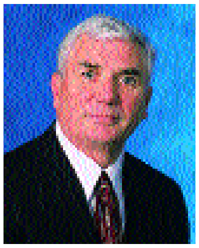
Melvyn N. Klein, 58, was elected to the Board of Directors in 2000. Prior to that, he served as a Director of Santa Fe Snyder Corporation. He is an attorney and counselor at law, private investor, and the sole stockholder of a general partner in GKH Partners, L.P., an investment partnership. Mr. Klein is also a Director of Anixter International, Bayou Steel Corporation, Hanover Compressor Corporation and ACTV, Inc.



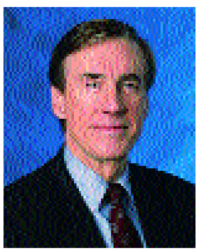
Robert A. Mosbacher, Jr., 49, was elected to the Board of Directors in 1999. He is President and Vice Chairman of Mosbacher Energy Company, Vice Chairman of Mosbacher Power Group, and a Director of JPMorgan Chase and Company. Mr. Mosbacher was previously a Director of PennzEnergy Company beginning in 1998, and served on the Executive Committee. He serves on the Executive Committee of the U.S. Oil & Gas Association. He received his Bachelor's of Arts degree in Government from Georgetown University and his Juris Doctorate degree from Southern Methodist University School of Law.



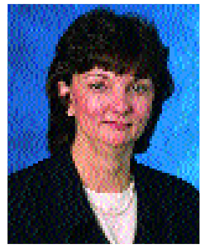
Robert B. Weaver, 62, was elected to the Board of Directors in 1999. He served as an energy finance specialist of the Chase Manhattan Bank, N.A., where he was in charge of its worldwide energy group from 1981 until his retirement in 1994. Mr. Weaver was previously a Director of PennzEnergy Company beginning in 1998, was Chairman of the Audit Committee and served on the Compensation Committee.



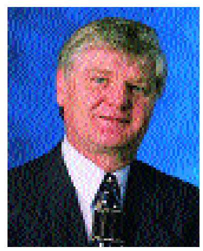
J. Michael Lacey, 55, was elected to the position of Senior Vice President - Exploration and Production in 1999. Mr. Lacey had previously joined Devon as Vice President of Operations and Exploration in 1989. Prior to his employment with Devon, Mr. Lacey served as General Manager in Tenneco Oil Company's Mid-Continent and Rocky Mountain Divisions. He is a registered professional engineer. He is a member of the Society of Petroleum Engineers and the American Association of Petroleum Geologists. Mr. Lacey holds both undergraduate and graduate degrees in petroleum engineering from the Colorado School of Mines.



Duke R. Ligon, 59, was elected to the position of Senior Vice President – General Counsel in 1999. Mr. Ligon joined Devon in 1997 as Vice President – General Counsel. In addition to Mr. Ligon's primary role of managing Devon's corporate legal matters (including litigation), he has direct involvement with Devon's governmental affairs, purchasing and merger and acquisition activities. Prior to joining Devon, Mr. 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 for 10 years. Mr. 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. Mr. Ligon holds an undergraduate degree in chemistry from Westminister College and a law degree from the University of Texas School of Law.



Marian J. Moon, 50, was elected to the position of Senior Vice President – Administration in1999. Ms. Moon is responsible for Human Resources, Office Administration, Information Technology and Corporate Governance. Ms. Moon has been with Devon for 17 years, serving in various capacities, including Manager of Corporate Finance. Prior to joining Devon, Ms. Moon was employed for 11 years by Amarex, Inc., an Oklahoma City based oil and natural gas production and exploration firm, where she served most recently as Treasurer. Ms. Moon is a member of the American Society of Corporate Secretaries. She is a graduate of Valparaiso University.



Darryl G. Smette, 53, was elected to the position of Senior Vice President – Marketing in 1999. Mr. Smette previously held the position of Vice President-Marketing and Administrative Planning since 1989. He joined Devon in 1986 as Manager of Gas Marketing. His marketing background includes 15 years with Energy Reserves Group, Inc./BHP Petroleum (Americas), Inc., 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. Mr. 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.

SENIOR VICE PRESIDENTS

H. Allen Turner, 48, was elected to the position of Senior Vice President – Corporate Development in 1999. Mr. Turner previously held the position of Vice President of Corporate Development and has been responsible for Devon's corporate finance, capital formation and merger and acquisitions activities since 1982. In 1981 he served as Executive Vice President of Palo Pinto/Harken Drilling Programs. For the six prior years he was associated with Merrill Lynch with various responsibilities including Regional Tax Investments Manager. He is a member of the Petroleum Investor Relations Association. He has served on the Capital Markets Committee of the Independent Petroleum Association of America and served as Chairman of the IPAA Oil and Gas Symposium. Mr. Turner is a member of the Financial Executives Institute and he attended Duke University.

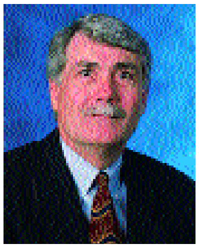
William T. Vaughn, 54, was elected to the position of Senior Vice President – Finance in 1999. Mr. Vaughn previously served as Devon's Vice President of Finance in charge of commercial banking functions, accounting, tax and information services since 1987. Prior to that, he was Controller of Devon from 1983 to 1987. Mr. 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. He is a graduate of the University of Arkansas with a Bachelor's of Science degree.

INTERNATIONAL OFFICERS

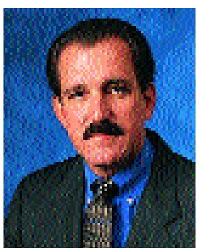
Duane C. Radtke, 51, was elected to the position of President of Devon International Corporation in September 2000. Mr. Radtke previously served as Executive Vice President, Exploration and Production, for Santa Fe Snyder Corporation. Prior to the May 1999 merger with Snyder Oil Corporation, Mr. Radtke served as Senior Vice President, Production, for Santa Fe Energy Resources. He joined the Company in 1992 through the merger of Santa Fe Energy and Adobe Oil Corporation. In 1993, Mr. Radtke became President of Santa Fe Energy Companies S.E. Asia in Jakarta, Indonesia, and was an officer and on the Board of Directors of the Indonesian Petroleum Association. He began his professional career with Texas Pacific Oil Company in Midland, Texas in 1971. Mr. Radtke received a Bachelor of Science degree in Mining Engineering in 1971 from the University of Wisconsin. He is a member of the Society of Petroleum Engineers, American Association of Petroleum Geologists and Rocky Mountain Association of Geologists.

John Richels, 50, was appointed in 1999 to the position of Chief Executive Officer of Northstar Energy Corporation, Devon's Canadian subsidiary. Mr. Richels served as Northstar's Executive Vice President and Chief Financial Officer from 1996 to 1998, and was on its Board of Directors from 1993 to 1996. Prior to joining Northstar, Mr. Richels was Managing Partner, Chief Operating Partner and a member of the Executive Committee of the Canadian based national law firm, Bennett Jones. Mr. Richels also served, on a secondment from Bennett Jones, as General Counsel of the XV Olympic Winter Games Organizing Committee in Calgary, Alberta. Mr. Richels has 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. He holds a bachelor's degree in economics from York University and a law degree from the University of Windsor.

OTHER OFFICERS



Rick D. Clark, 53, was elected to the position of Vice President and General Manager – Permian/Mid-Continent Division in 1999. Mr. Clark previously served as Production/Operations Manager since joining Devon in 1995. As such, he was responsible for the company's drilling and production activities. Prior to joining Devon, Mr. Clark was employed by Patrick Petroleum Company where he served since 1988 as Executive Vice President, Operations and Corporate Development. Prior to 1988, Mr. 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. Mr. Clark holds a professional degree in Petroleum Engineering from the Colorado School of Mines.



Don D. DeCarlo, 44, was elected to the position of Vice President and General Manager – Rocky Mountain Division in September 2000. Mr. DeCarlo previously served as Vice President and General Manager, Rocky Mountain Division, for Santa Fe Snyder Corporation. Mr. 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, Mr. DeCarlo held management positions of increasing responsibilities in: Bakersfield, California; Midland, Texas and most recently in Denver, Colorado. He received a Bachelor of Science degree in Petroleum Engineering from West Virginia University in 1978. He 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.

Danny J. Heatly, 45, was elected to the position of Vice President – Accounting in 1999. Mr. Heatly had previously served as Devon's Controller since 1989. Prior to joining Devon, Mr. 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. He graduated with a Bachelor's of Accountancy degree from the University of Oklahoma.

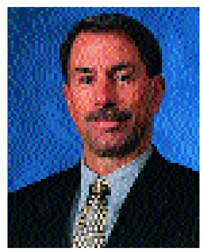
Brian J. Jennings, 40, was elected to the position of Vice President – Corporate Finance in March 2000. Prior to joining Devon, Mr. Jennings was a Managing Director in the Energy Investment Banking Group of PaineWebber, Inc. He began his banking career at Kidder, Peabody before moving to Lehman Brothers and later to PaineWebber. Mr. Jennings specialized in providing strategic advisory and corporate finance services to public and private companies in the E&Pand oilfield service sectors. He began his energy career with ARCO International Oil & Gas, a subsidiary of Atlantic Richfield Company. Mr. Jennings received his Bachelor of Science in Petroleum Engineering from the University of Texas at Austin and his Master of Business Administration from the University of Chicago's Graduate School of Business.

OTHER OFFICERS

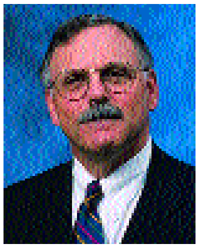
Richard E. Manner, 53, was elected to the position of Vice President – Information Services in July 2000. Mr. Manner has been an Information Technology professional for 25 years. Prior to joining Devon, he was employed by Unisys in Houston, Texas. There he served for 14 years in various positions including Director of Information Systems. Prior to his tenure with Unisys, Mr. 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. Mr. Manner received his electrical engineering degree from the University of Oklahoma.

R. Alan Marcum, 34, was elected to the position of Controller in 1999. Mr. Marcum has been with Devon since 1995, most recently having held the position of Assistant Controller. He is responsible for revenue, joint interest, international and operations accounting for Devon. Prior to joining Devon, Mr. 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, majoring in Accounting and Finance, and is a Certified Public Accountant and a member of the Oklahoma State Society of Certified Public Accountants.

Gary L. McGee, 51, was elected to the position of Vice President – Government Relations in 1999. Mr. McGee had previously served as Devon's Treasurer since 1983, having first served as Controller. Mr. McGee is a member of the Petroleum Association of Wyoming and the New Mexico Oil & Gas Association. He served as Vice President of Finance with KSA Industries, Inc., a private holding company with various interests including oil and gas exploration. Mr. McGee also held various accounting positions with Adams Resources and Energy Company and Mesa Petroleum Company. He received his accounting degree from the University of Oklahoma.



Paul R. Poley, 47, was elected to the position of Vice President – Human Resources in March 2000. Mr. 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, Mr. Poley was Regional Personnel Manager for International Mill Service, Inc. He received his Bachelor's of Arts degree in Sociology from Bucknell University.



William A. Van Wie, 55, was elected to the position of Vice President and General Manager – Southern Division in 1999. Mr. Van Wie previously served as Senior Vice President and General Manager – Offshore for PennzEnergy. Mr. Van Wie 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 he rejoined 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 and is also a member of the National Ocean Industries Association. Mr. Van Wie received his Bachelor 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, 43, was elected to the position of Vice President – Communications and Investor Relations in 1999. He has primary responsibility for Devon's investor communications, media relations and employee communications. Mr. White had previously served as Devon's 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). Mr. 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. Mr. White received his Bachelor of Accounting degree from the University of Texas at Arlington.

Dale T. Wilson, 41, was elected to the position of Treasurer of Devon in 1999. He has primary responsibility of the company's treasury and risk management functions. Prior to joining Devon, Mr. Wilson was employed in the banking industry for 17 years and was employed by Bank of America for the 15 years prior to joining Devon, as a Managing Director of the Energy Finance Group. Mr. Wilson has been active in oil and gas trade associations such as the Permian Basin Petroleum Association, the New Mexico Oil & Gas Association and the Texas Independent Producers & Royalty Owners Association. He is a 1982 graduate of Baylor University with a bachelor's degree in finance and accounting.

GLOSSARY

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.

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 (NGL): Liquid hydrocarbons that are extracted and separated from the natural gas stream. NGL products include ethane, propane, butane and natural gasoline.

Net acres: Gross acres multiplied by one's fractional working interest in the property.

Pilot program: A small-scale test project used to assess the viability of a concept prior to committing significant capital to a large-scale project.

Production: Natural resources, such as oil or gas, taken out of the ground.
- *Gross production*: Total production before deducting royalties.
- *Net production*: Gross production, minus royalties, multiplied by one's fractional working interest.

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

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Oklahoma City, OK 73102-8260

Gulf Division
Devon Energy Corporation
Two Allen Center
1200 Smith Street, Suite 3300
Houston, TX 77002

International Division
Devon Energy Corporation
840 Gessner, Suite 1400
Houston, TX 77024

Canadian Division
Northstar Energy 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 Trust Company, N.A.
Client Administration
P.O. Box 8029
Boston, MA 02266-8029
Toll Free: 1-800-733-5001
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: 1-800-387-0825

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News by Fax
Faxed copies of quarterly earnings releases and other press releases can be requested 24 hours a day by calling 1-800-758-5804, Ext. 118040.

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 on Thursday, May 17, 2001, in 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 44,000 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.

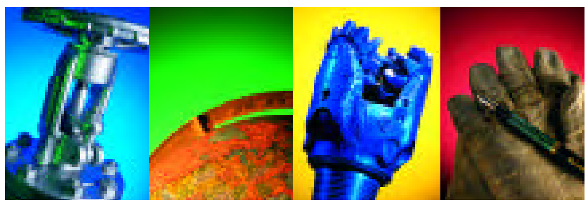
COMMON STOCK TRADING DATA

QUARTER	HIGH	LOW	LAST	VOLUME
1999				
First	**$ 31.75**	**20.13**	**27.56**	**14,271,200**
Second	**$ 37.44**	**26.13**	**35.75**	**14,221,500**
Third	**$ 44.94**	**33.00**	**41.44**	**39,958,800**
Fourth	**$ 42.00**	**29.50**	**32.88**	**31,130,200**
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**

LEGEND TO TOOL PHOTOGRAPHS

Page 4 - This 6 1/2" tooth bit, courtesy of Halliburton, is a common tool in the drilling of oil and gas wells.

Page 28 - This flow valve, courtesy of Wilson Supply, controls the flow of crude oil through a pipeline.



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