DEVON ENERGY CORP/DE
Form 10-K405
March 19, 2002

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

(Mark One)
X ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE

SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2001
OR
TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE

SECURITIES EXCHANGE ACT OF 1934
Commission File Number 000-30176

DEVON ENERGY CORPORATION
(Exact Name of Registrant as Specified in its Charter)

DELAWARE (State or Other Jurisdiction of Incorporation or Organization)	73-1567067 (I.R.S. Employer Identification No.)
20 NORTH BROADWAY OKLAHOMA CITY, OKLAHOMA (Address of Principal Executive Offices)	73102-8260 (Zip Code)

Registrant's telephone number, including area code: (405) 235-3611

Securities registered pursuant to Section 12(b) of the Act:

TITLE OF EACH CLASS	NAME OF EACH EXCHANGE ON WHICH REGISTERED
Common Stock, par value $.10 per share	American Stock Exchange
4.9% Convertible Debentures, due 2008	The New York Stock Exchange
4.95% Convertible Debentures, due 2008	The New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: NONE

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.
Yes x No
---- ----

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of Registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. x

The aggregate market value of the voting stock held by non-affiliates of the Registrant as of March 14, 2002, was $7,202,248,538. At such date 154,117,214 shares of common stock and 2,005,569 exchangeable shares of Devon's wholly-owned subsidiary, Northstar Energy Corporation, were outstanding. Each exchangeable share is exchangeable for one share of Devon common stock. .

DOCUMENTS INCORPORATED BY REFERENCE

Proxy statement for the 2002 annual meeting of stockholders - Part III

TABLE OF CONTENTS

DEFINITIONS

As used in this document:

"Mcf" means thousand cubic feet

"MMcf" means million cubic feet

"Bcf" means billion cubic feet

"MMBtu" means million British thermal units, a measure of heating value

"Bbl" means barrel

"MBbls" means thousand barrels

"MMBbls" means million barrels

"Boe" means equivalent barrels of oil

"MBoe" means thousand equivalent barrels of oil

"MMBoe" means million equivalent barrels of oil

"Oil" includes crude oil and condensate

"NGLs" means natural gas liquids

"Domestic" means the properties of the Company in the onshore continental United States and the offshore Gulf of Mexico

"Permian/Mid-Continent, Rocky Mountain and Gulf" means the divisions of the Company with properties in the onshore continental United States and the offshore properties in the Gulf of Mexico
"Canada" means the division of the Company encompassing oil and gas properties located in the Western Canadian Sedimentary Basin in Alberta and British Columbia
"International" means the division of the Company encompassing oil and gas properties that lie outside the United States and Canada

2

DISCLOSURE REGARDING FORWARD-LOOKING STATEMENTS

This report includes "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements other than statements of historical facts included or incorporated by reference in this report, including, without limitation, statements regarding the Company's future financial position, business strategy, budgets, projected costs and plans and objectives of management for future operations, are forward-looking statements. In addition, forward-looking statements generally can be identified by the use of forward-looking terminology such as "may," "will," "expect," "intend," "project," "estimate," "anticipate," "believe," or "continue" or the negative thereof or variations thereon or similar terminology. Although the Company believes that the expectations reflected in such forward-looking statements are reasonable, it can give no assurance that such expectations will prove to have been correct. Important factors that could cause actual results to differ materially from the Company's expectations ("Cautionary Statements") include, but are not limited to, the Company's assumptions about energy markets, production levels, reserve levels, operating results, competitive conditions, technology, the availability of capital resources, capital expenditure obligations, the supply and demand for oil, natural gas, NGLs and other products or services, the price of oil, natural gas, NGLs and the other products or services, currency exchange rates, the weather, inflation, the availability of goods and services, drilling risks, future processing volumes and pipeline throughput, costs or difficulties related to the integration of the businesses of Devon, Mitchell Energy & Development Corp. ("Mitchell") and Anderson Exploration Ltd. ("Anderson"), general economic conditions, either internationally or nationally or in the jurisdictions in which Devon or its subsidiaries are doing business, legislative or regulatory changes, including changes in environmental regulation, environmental risks and liability under federal, state and foreign environmental laws and regulations, the securities or capital markets and other factors disclosed under "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations," "Item 2. Properties - Proved Reserves and Estimated Future Net Revenue" and elsewhere in this report. All subsequent written and oral forward-looking statements attributable to the Company, or persons acting on its behalf, are expressly qualified in their entirety by the cautionary statements. The Company assumes no duty to update or revise its forward-looking statements based on changes in internal estimates or expectations or otherwise.

3

PART I

ITEM 1. BUSINESS

GENERAL

Devon Energy Corporation, including its subsidiaries, ("Devon" or the

"Company") is an independent energy company engaged primarily in oil and gas exploration, development and production, acquisition of producing properties, transportation of oil and gas and processing of natural gas. Through its predecessors, Devon began operations in 1971 as a privately-held company. In 1988, the Company's common stock began trading publicly on the American Stock Exchange under the symbol DVN. In addition, commencing on December 15, 1998, a new class of Devon exchangeable shares began trading on The Toronto Stock Exchange under the symbol NSX. These shares are essentially equivalent to Devon common stock. However, because they are issued by Devon's wholly-owned subsidiary, Northstar Energy Corporation ("Northstar"), they qualify as a domestic Canadian investment for Canadian institutional shareholders. They are exchangeable at any time, on a one-for-one basis, for common shares of Devon.

The principal and administrative offices of Devon are located at 20 North Broadway, Oklahoma City, OK 73102-8260 (telephone 405/235-3611).

Devon currently owns oil and gas properties concentrated in five operating divisions: the Permian/Mid-Continent, Rocky Mountain and Gulf divisions include onshore properties in the continental United States and offshore properties primarily in the Gulf of Mexico; Canada, which includes properties in the Western Canadian Sedimentary Basin in Alberta and British Columbia; and the International Division, which includes properties in Argentina, Azerbaijan, China, Indonesia and West Africa. In addition, Devon created a sixth operating division to incorporate its U.S. midstream activities with its marketing activities. The responsibilities of the Marketing and Midstream Division include marketing natural gas, crude oil and NGLs. The division is also responsible for the construction and operation of pipelines, storage and treating facilities and gas processing plants. These services are performed for Devon as well as for unrelated third parties. (A detailed description of the significant properties can be found under "Item 2. Properties - Significant Properties" beginning on page 16 hereof).

At December 31, 2001, Devon's estimated proved reserves were 1,620 MMBoe, of which 56% were natural gas reserves and 44% were oil and NGLs reserves. The present value of pre-tax future net revenues discounted at 10% per annum assuming essentially constant prices ("10% Present Value") of such reserves was $7.2 billion. After taxes, the present value was $5.3 billion. Devon is one of the top five public independent oil and gas companies based in the United States, as measured by oil and gas reserves.

STRATEGY

Devon's primary objectives are to build reserves, production, cash flow and earnings per share by (a) acquiring oil and gas properties, (b) exploring for new oil and gas reserves and (c) optimizing production and value from existing oil and gas properties. Devon's management seeks

to achieve these objectives by (a) concentrating its properties in core areas to achieve economies of scale, (b) acquiring and developing high profit margin properties, (c) continually disposing of marginal and non-strategic properties, (d) balancing reserves between oil and gas, (e) maintaining a high degree of financial flexibility, and (f) enhancing the value of Devon's production through marketing and midstream activities.

During 1988, Devon expanded its capital base with its first issuance of common stock to the public. This transaction began a substantial expansion program that has continued through the subsequent years. Devon has used a two-pronged strategy of acquiring producing properties and engaging in drilling activities to achieve this expansion. Total proved reserves increased from 8.1 MMBoe at year-end 1987 (without giving effect to the 1998 and 2000 mergers accounted for as poolings of interests) to 1,620 MMBoe at year-end 2001.

Devon's objective, however, is to increase value per share, not simply to increase total assets. Reserves have grown from 1.31 Boe per share at year-end 1987 (without giving effect to the 1998 and 2000 poolings) to 12.84 Boe per share at year-end 2001. This represents a compound annual growth rate of 17.7%. Another measure of value per share is oil and gas production per share. Production increased from 0.18 Boe per share in 1987 (without giving effect to the 1998 and 2000 poolings) to 1.07 Boe per share in 2001, a compound annual growth rate of 13.6%.

DEVELOPMENT OF BUSINESS

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

Following the Mitchell merger announcement, Devon announced on September 4, 2001, that it had entered into an agreement to acquire Anderson Exploration Ltd. ("Anderson") for approximately $3.5 billion in cash. This acquisition closed on October 15, 2001, and therefore had an impact on Devon's results for the last two and one-half months of the year.

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

The remaining $3 billion of the $6 billion of long-term debt is in the form of a credit facility that bears interest at floating rates. At December 31, 2001, $1 billion of this facility was borrowed. Following the close of the Mitchell transaction, the $3 billion facility was fully borrowed. Principal payments due on this debt are $0.2 billion in October 2004, $1.2 billion in

5

2005 and $1.6 billion in 2006. The 2005 and 2006 payments are split equally in payments due in April and October of those years. The interest rate on this debt at December 31, 2001 was 2.9%.

FINANCIAL INFORMATION ABOUT SEGMENTS AND GEOGRAPHICAL AREAS

Note 17 to the consolidated financial statements included in (Item 8. Financial Statements and Supplemental Data) of this report contains information on Devon's segments and geographical areas.

DRILLING ACTIVITIES

Devon is engaged in numerous drilling activities on properties presently owned and intends to drill or develop other properties acquired in the future. Devon's 2002 drilling activities will be focused in the Rocky Mountains, Permian Basin, Mid-Continent, Gulf of Mexico and onshore Gulf Coast areas in the

U.S., the Western Sedimentary areas of Canada and in China and West Africa outside North America.

6

The following tables set forth the results of Devon's drilling activity for the past five years.

UNITED STATES PROPERTIES

	Development Wells						Explorato		
	Gross (1)			Net (2)			Gross (1)		
	Productive	Dry	Total	Productive	Dry	Total	Productive	Dry	Total
1997	484	17	501	303.00	9.10	312.10	30	23	53
1998	374	1	375	153.69	0.10	153.79	24	21	45
1999	547	8	555	345.35	3.80	349.15	71	9	80
2000	890	13	903	512.18	6.80	518.98	95	11	106
2001	961	19	980	638.26	12.91	651.17	148	17	165
Total	3,256	58	3,314	1,952.48	32.71	1,985.19	368	81	449

CANADIAN PROPERTIES

	Development Wells						Explorato		
	Gross (1)			Net (2)			Gross (1)		
	Productive	Dry	Total	Productive	Dry	Total	Productive	Dry	Total
1997	126	29	155	88.20	23.20	111.40	55	48	103
1998	112	15	127	74.88	11.04	85.92	45	37	82
1999	65	9	74	29.61	3.45	33.06	39	23	62
2000	130	6	136	68.74	3.25	71.99	70	27	97
2001	163	26	189	100.91	16.53	117.44	82	21	103
Total	596	85	681	362.34	57.47	419.81	291	156	447

INTERNATIONAL PROPERTIES

	Development Wells			Explorato
	Gross (1)	Net (2)	Gross (1)	

	Productive	Dry	Total	Productive	Dry	Total	Productive	Dry	Total
1997	43	2	45	10.00	0.60	10.60	1	5	6
1998	59	2	61	18.90	0.60	19.50	9	18	27
1999	42	2	44	10.00	0.60	10.60	1	4	5
2000	75	1	76	19.71	0.50	20.21	1	9	10
2001	84	1	85	21.71	0.51	22.22	6	17	23
Total	303	8	311	80.32	2.81	83.13	18	53	71

TOTAL PROPERTIES

	Development Wells						Explorato		
	Gross (1)			Net (2)			Gross (1)		
	Productive	Dry	Total	Productive	Dry	Total	Productive	Dry	Total
1997	653	48	701	401.20	32.90	434.10	86	76	162
1998	545	18	563	247.47	11.74	259.21	78	76	154
1999	654	19	673	384.96	7.85	392.81	111	36	147
2000	1,095	20	1,115	600.63	10.55	611.18	166	47	213
2001	1,208	46	1,254	760.88	29.95	790.83	236	55	291
Total	4,155	151	4,306	2,395.14	92.99	2,488.13	677	290	967

(1) Gross wells are the sum of all wells in which Devon owns an interest.

(2) Net wells are the sum of Devon's working interests in gross wells.

7

As of December 31, 2001, Devon was participating in the drilling of 45 gross (27.58 net) wells in the U.S., 35 gross (23.31 net) wells in Canada and 18 gross (7.96 net) wells internationally. Of these wells, through February 15, 2002, 22 gross (14.24 net) wells in the U.S., 26 gross (18.00 net) wells in Canada and 6 gross (1.15 net) wells internationally had been completed as productive. An additional 2 gross (2.00 net) wells in the U.S., 2 gross (2.00 net) wells in Canada and 1 gross (0.50 net) well internationally were dry holes. The remaining wells were still in process.

CUSTOMERS

Devon sells its gas production to a variety of customers including pipelines, utilities, gas marketing firms, industrial users and local distribution companies. Existing gathering systems and interstate and intrastate pipelines are used to consummate gas sales and deliveries.

The principal customers for Devon's crude oil production are refiners, remarketers and other companies, some of which have pipeline facilities near the producing properties. In the event pipeline facilities are not conveniently available, crude oil is trucked or barged to storage, refining or pipeline facilities.

For the years ended December 31, 2001 and 2000, one significant purchaser, Enron Capital and Trade Resource Corporation ("Enron"), accounted for 16% and 20%, respectively, of Devon's combined oil, gas and NGLs sales. No purchaser accounted for over 10% of such revenues in 1999. Devon does not consider itself dependent upon this purchaser, since other purchasers are willing to purchase this same production at competitive prices.

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

OIL AND NATURAL GAS MARKETING

Oil Marketing. Devon's oil production is sold under both long-term and short-term agreements at prices negotiated with third parties. Devon periodically enters into financial commodity hedging activities with a portion of its oil production which are intended to support its oil price at targeted levels and to manage the Company's exposure to oil price fluctuations. (See "Item 7A. Quantitative and Qualitative Disclosures About Market Risk.")

Natural Gas Marketing. Devon's gas production is also sold under both long-term and short-term agreements at prices negotiated with third parties. Devon periodically enters into financial commodity hedging activities with a portion of its gas production which are intended to support its gas price at targeted levels and to manage the Company's exposure to gas price fluctuations. Although exact percentages vary daily, as of February 2002 approximately 65% of Devon's natural gas production was sold under short-term contracts at variable or market-sensitive prices. These market-sensitive sales are referred to as "spot market" sales. Another 26% were committed under various long-term contracts (one year or more) which dedicate the natural gas to a purchaser for an

extended period of time, but still at market sensitive prices. Devon's remaining gas production was sold under fixed price contracts: 8% under short-term agreements and 1% under long-term contracts.

Under both long-term and short-term contracts, typically either the entire contract (in the case of short-term contracts) or the price provisions of the contract (in the case of long-term contracts) are re-negotiated from daily intervals up to one-year intervals. The spot market has become progressively more competitive in recent years. As a result, prices on the spot market have been volatile.

The spot market is subject to volatility as supply and demand factors in various regions of North America fluctuate. In addition to fixed price contracts, Devon periodically enters into hedging arrangements or firm delivery commitments with a portion of its gas production. These activities are intended to support targeted gas price levels and to manage the Company's exposure to gas price fluctuations. (See "Item 7A. Quantitative and Qualitative Disclosures About Market Risk.")

COMPETITION

The oil and gas business is highly competitive. Devon encounters competition by major integrated and independent oil and gas companies in acquiring drilling prospects and properties, contracting for drilling equipment and securing trained personnel. Intense competition occurs with respect to marketing, particularly of natural gas. Certain competitors have resources that substantially exceed those of Devon.

SEASONAL NATURE OF BUSINESS

Generally, but not always, the demand for natural gas decreases during the summer months and increases during the winter months. Seasonal anomalies such as mild winters sometimes lessen this fluctuation. In addition, pipelines, utilities, local distribution companies and industrial users utilize natural gas storage facilities and purchase some of their anticipated winter requirements during the summer. This can also lessen seasonal demand fluctuations.

GOVERNMENT REGULATION

Devon's operations are subject to various levels of government controls and regulations in the United States, Canada and internationally.

UNITED STATES REGULATION

In the United States, legislation affecting the oil and gas industry has been pervasive and is under constant review for amendment or expansion. Pursuant to such legislation, numerous federal, state and local departments and agencies have issued extensive rules and regulations binding on the oil and gas industry and its individual members, some of which carry substantial penalties for failure to comply. Such laws and regulations have a significant impact on oil and gas drilling, gas processing plants and production activities, increase the cost of doing business and, consequently, affect profitability. Inasmuch as new legislation affecting the oil and gas industry is commonplace and existing laws and regulations are frequently amended or reinterpreted, Devon is unable to predict the future cost or impact of complying with such laws and regulations. The Company considers the cost of environmental protection a necessary and manageable part of its business. The Company has been able to plan for and comply with new environmental initiatives without materially altering its operating strategies.

Exploration and Production. Devon's United States operations are subject to various types of regulation at the federal, state and local levels. Such regulation includes requiring permits for the drilling of wells; maintaining bonding requirements in order to drill or operate wells; implementing spill prevention plans; submitting notification and receiving permits relating to the presence, use and release of certain materials incidental to oil and gas operations; and regulating the location of wells, the method of drilling and casing wells, the use, transportation, storage and disposal of fluids and materials used in connection with drilling and production activities, surface usage and the restoration of properties upon which wells have been drilled, the plugging and abandoning of wells and the transporting of production. Devon's operations are also subject to various conservation matters, including the regulation of the size of drilling and spacing units or proration units, the number of wells which may be drilled in a unit, and the unitization or pooling of oil and gas properties. In this regard, some states allow the forced pooling or integration of tracts to facilitate exploration while other states rely on voluntary pooling of lands and leases, which may make it more difficult to develop oil and gas properties. In addition, state conservation laws establish maximum rates of production from oil and gas wells, generally limit the venting or flaring of gas, and impose certain requirements regarding the ratable purchase of production. The effect of these regulations is to limit the amounts of oil and gas Devon can produce from its wells and to limit the number of wells or the locations at which Devon can drill.

Certain of Devon's oil and gas leases, including its offshore Gulf of Mexico leases, most of its leases in the San Juan Basin and many of the Company's leases in southeast New Mexico and Wyoming, are granted by the federal government and administered by various federal agencies, including the Minerals Management Service of the Department of the Interior ("MMS"). Such leases require compliance with detailed federal regulations and orders which regulate, among other matters, drilling and operations on lands covered by these leases, and calculation and disbursement of royalty payments to the federal government. The MMS has been particularly active in recent years in evaluating and, in some cases, promulgating new rules and regulations regarding competitive lease bidding and royalty payment obligations for production from federal lands. The Federal Energy Regulatory Commission ("FERC") also has jurisdiction over certain offshore activities pursuant to the Outer Continental Shelf Lands Act.

Environmental and Occupational Regulations. Various federal, state and local laws and regulations concerning the discharge of incidental materials into the environment, the generation, storage, transportation and disposal of contaminants or otherwise relating to the protection of public health, natural resources, wildlife and the environment, affect Devon's exploration, development, processing, and production operations and the costs attendant thereto. These laws and regulations increase Devon's overall operating expenses. Devon maintains levels of insurance customary in the industry to limit its financial exposure in the event of a substantial environmental claim resulting from sudden, unanticipated and accidental discharges of oil, salt water or other substances. However, 100% coverage is not maintained concerning any environmental claim, and no coverage is maintained with respect to any penalty or fine required to be paid by Devon because of its violation of any federal, state or local law. Devon is committed to meeting its responsibilities to protect the environment wherever it operates and anticipates making increased expenditures of both a capital and expense nature as a result of the increasingly stringent laws relating to the protection of the environment. Devon's unreimbursed expenditures in 2001 concerning such matters were immaterial, but Devon cannot predict with any reasonable degree of certainty its future exposure concerning such matters. The Company considers the cost of environmental protection a necessary and manageable part of its business. The Company has been able to plan for and comply with new environmental initiatives without materially altering its operating strategies.

Devon is also subject to laws and regulations concerning occupational safety and health. Due to the continued changes in these laws and regulations, and the judicial construction of same, Devon is unable to predict with any reasonable degree of certainty its future costs of complying with these laws and regulations. The Company considers the cost of environmental protection a necessary and manageable part of its business. The Company has been able to plan for and comply with new environmental initiatives without materially altering its operating strategies.

Devon has historically maintained its own internal Environmental, Health and Safety Department. This department is responsible for instituting and maintaining an environmental and safety compliance program for Devon. The program includes field inspections of properties and internal assessments of Devon's compliance procedures.

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 potential 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 historical operations acquired in historical and recent mergers are involved in matters in which it has been alleged that such subsidiaries are potentially responsible parties ("PRPs") under CERCLA or similar state legislation with respect to various waste disposal areas owned or operated by third parties. As of December 31, 2001, Devon's consolidated balance sheet

11

included $8 million of accrued liabilities, reflected in "Other liabilities," for environmental remediation. Devon does not currently believe there is a reasonable possibility of incurring additional material costs in excess of the current accruals recognized for such environmental remediation activities. With respect to the sites in which Devon subsidiaries are PRPs, Devon's conclusion is based in large part on (i) the availability of defenses to liability, including the availability of the "petroleum exclusion" under CERCLA and similar state laws, and/or (ii) Devon's current belief that its share of wastes at a particular site is or will be viewed by the Environmental Protection Agency or other PRPs as being de minimis. As a result, Devon's monetary exposure is not expected to be material.

CANADIAN REGULATIONS

The oil and gas industry in Canada is subject to extensive controls and regulations imposed by various levels of government. It is not expected that any of these controls or regulations will affect Devon's Canadian operations in a manner materially different than they would affect other oil and gas companies of similar size. The following are the most important areas of control and regulation.

The North American Free Trade Agreement. The North American Free Trade Agreement ("NAFTA") which became effective on January 1, 1994 carries forward most of the material energy terms contained in the Canada-U.S. Free Trade Agreement. In the context of energy resources, Canada continues to remain free to determine whether exports to the United States or Mexico will be allowed, provided that any export restrictions do not (i) reduce the proportion of energy exported relative to the supply of the energy resource; (ii) impose an export price higher than the domestic price; or (iii) disrupt normal channels of supply. All parties to NAFTA are also prohibited from imposing minimum export or import price requirements.

Royalties and Incentives. Each province and the federal government of Canada have legislation and regulations governing land tenure, royalties, production rates and taxes, environmental protection and other matters under their respective jurisdictions. The royalty regime is a significant factor in the profitability of oil and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiations between the parties. Crown royalties are determined by government regulation and are generally calculated as a percentage of the value of the gross production with the royalty rate dependent in part upon prescribed reference prices, well productivity, geographical location, field discovery date and the type and quality of the petroleum product produced. From time to time, the governments of Canada, Alberta and British Columbia have also established incentive programs such as royalty rate reductions, royalty holidays and tax credits for the purpose of encouraging oil and natural gas exploration or enhanced recovery projects. These incentives generally have the effect of increasing the cash flow to the producer.

Pricing and Marketing. The price of oil and natural gas sold is determined by negotiation between buyers and sellers. An order from the National Energy Board ("NEB") is required for oil exports from Canada. Any oil export to be made pursuant to an export contract of longer than one year, in the case of light crude, and two years, in the case of heavy crude, duration (up to 25 years) requires an exporter to obtain an export license from the NEB. The issue of such a license requires the approval of the Governor in Council. Natural gas exported from Canada is also subject to similar regulation by the NEB. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts in excess of two years must continue to meet certain criteria

12

prescribed by the NEB. The governments of Alberta and British Columbia also regulate the volume of natural gas which may be removed from those provinces for consumption elsewhere based on such factors as reserve availability, transportation arrangements and market considerations.

Environmental Regulation. The oil and natural gas industry is subject to environmental regulation pursuant to local, provincial and federal legislation. Environmental legislation provides for restrictions and prohibitions on releases or emissions of various substances produced or utilized in association with certain oil and gas industry operations. In addition, legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. A breach of such legislation may result in the imposition of fines and penalties. Devon is committed to meeting its responsibilities to protect the environment wherever it operates and anticipates making increased expenditures of both a capital and expense nature as a result of the increasingly stringent laws relating to the protection of the environment. Devon's unreimbursed expenditures in 2001 concerning such matters were immaterial, but Devon cannot predict with any reasonable degree of certainty its future exposure concerning such matters.

Investment Canada Act. The Investment Canada Act requires Government of Canada approval, in certain cases, of the acquisition of control of a Canadian business by an entity that is not controlled by Canadians. In certain circumstances, the acquisition of natural resource properties may be considered to be a transaction requiring such approval.

INTERNATIONAL REGULATIONS

The oil and gas industry is subject to various types of regulation throughout the world. Legislation affecting the oil and gas industry has been pervasive and is under constant review for amendment or expansion. Pursuant to such legislation, government agencies have issued extensive rules and regulations binding on the oil and gas industry and its individual members, some of which carry substantial penalties for failure to comply. Such laws and regulations have a significant impact on oil and gas drilling and production activities, increase the cost of doing business and, consequently, affect profitability. Inasmuch as new legislation affecting the oil and gas industry is commonplace and existing laws and regulations are frequently amended or reinterpreted, Devon is unable to predict the future cost or impact of complying with such laws and regulations. The following are significant areas of regulation.

Exploration and Production. Devon's oil and gas concessions and permits are granted by host governments and administered by various foreign government agencies. Such foreign governments require compliance with detailed regulations and orders which regulate, among other matters, drilling and operations on areas covered by concessions and permits and calculation and disbursement of royalty payments, taxes and minimum investments to the government.

Regulation includes requiring permits for the drilling of wells; maintaining bonding requirements in order to drill or operate wells; implementing spill prevention plans; submitting notification and receiving permits relating to the presence, use and release of certain materials incidental to oil and gas operations; and regulating the location of wells, the method of drilling and casing wells, the use, transportation, storage and disposal of fluids and materials used in

connection with drilling and production activities, surface usage and the restoration of properties upon which wells have been drilled, the plugging and abandoning of wells and the transporting of production. Devon's operations are also subject to regulations which may limit the number of wells or the locations at which Devon can drill.

Environmental Regulations. Various government laws and regulations concerning the discharge of incidental materials into the environment, the generation, storage, transportation and disposal of contaminants or otherwise relating to the protection of public health, natural resources, wildlife and the environment, affect Devon's exploration, development, processing and production operations and the costs attendant thereto. In general, this consists of preparing Environmental Impact Assessments in order to receive required environmental permits to conduct drilling or construction activities. Such regulations also typically include requirements to develop emergency response plans, waste management plans, and spill contingency plans. In some countries, the application of worldwide standards, such as ISO 14000 governing Environmental Management Systems, are required to be implemented for international oil and gas operations.

Brazil has stringent environmental laws. The basic federal law governing the environment is Law No. 9.605 of February 12, 1998, which set up areas of conservation that receive federal protection. The governmental environmental agency is IBAMA, which has significant enforcement powers. Environmental Impact Studies are required to determine the impact of activities on the environment and provide ways to avoid or diminish negative effects of the project on the environment. CONAMA Resolution 23 of December 7, 1994 established licensing criteria for activities related to drilling and production. Prior to commencement of exploration activities, IBAMA or a state environmental agency inspects the equipment to be used and must grant a license; the inspection and grant of the license may cause delays in start-up of operations. In addition to federal regulations, state and local agencies may have additional jurisdiction. Damage to the environment results in strict liability to the holder of the Concession. Sanctions for violations can be civil, criminal and administrative in nature.

GOVERNMENT TAKES AND TAXATION

Foreign governments have been evaluating in recent years in and, in some cases, promulgating new rules and regulations regarding royalty payment obligations and taxes.

In Brazil there are numerous taxes imposed by federal, state and municipal governments on services and equipment, which require extensive record keeping and withholdings. Among the most significant are the following: Law No. 9.779 of 1999 extended the tax for income legal entities earn with the rendering of services, technical assistance and administrative services to 25%. There is a Value Added Sales Tax (ICMS) ranging between 7% and 25% and a municipal service tax (ISS), typically paid in the place of performance, of about 5%. Excise tax (IPI) is paid on all goods manufactured or imported into Brazil that average about 10% (see exception for imports of equipment for petroleum activities above). There are "social contribution" taxes for funding Brazil's extensive social welfare programs. COFINS, a social contribution tax charged on gross receipts, including financial and currency transactions and investments is 3%, and PIS, to fund the unemployment insurance program, is

14

financed by the employer at 0.65% of its gross monthly receipts. Additionally, there is a severance fund contribution (FGTS). A banking tax ("CPMF") on the debit of funds from an account is charges at 0.30%.

In Argentina Competitiveness Law No. 25,413 amended by Law 25,453 created a new tax applicable on bank credits and debits. The tax is applicable on (1) credits and debits on current accounts in financial entities subject to the Financial Entities Law; (2) the operations carried out by financial entities subject to the Financial Entities Law where the person/entity ordering the financial operation or the beneficiaries do not use the current accounts mentioned above, and (3) the movement or handing over of funds (whether owned or belonging to third parties), by any person or entity. The General Tax Rate (subject to certain tax credits) is 0.6% in the case of debits and credits. In the cases described in points 2 and 3 above, it will be deemed that said financial operations replace the corresponding debits and credits and the tax rate will be doubled.

GOVERNMENT AUTHORIZATIONS AND FILINGS.

Host country law and regulations in certain cases requires prior approval by the national government of any acquisition of concession and permits granting hydrocarbon rights and allowing petroleum operations to be conducted.

In Argentina, Section 72 of Hydrocarbons Law 17,319 provides that permits and concessions granted under this law may be assigned with the prior authorization of the Government to assignees who meet the conditions required to be a concession holder. Such prior approval of the Government would be required if the permits and concessions held by Devon were transferred directly to a purchaser as assets. However, according to the past practice of the Secretariat of Energy, indirect transfers of permits and concessions by sale of the stock have not been subject to the prior approval of the Government.

Subject to certain exemptions, Section 8 of Antitrust Law 25,156 as amended by Section 2 of National Executive Branch Decree No. 396/01, provides that the purchase of the property or any other right to shares or capital participations must be notified to the Comision Nacional de Defensa de la Competencia before execution or within a week after the transaction is closed, where the total volume of business of the participating companies exceeds US $200,000,000 in Argentina.

EMPLOYEES

As of December 31, 2001, Devon's staff consisted of 2,826 full-time employees. The Company also engages independent consulting petroleum engineers, environmental professionals, geologists, geophysicists, landmen and attorneys on a fee basis. The Company believes that it has good labor relations with its employees.

15

ITEM 2. PROPERTIES

Substantially all of Devon's properties consist of interests in developed and undeveloped oil and gas leases and mineral acreage located in the Company's core operating areas. These interests entitle Devon to drill for and produce oil, natural gas and NGLs from specific areas. Devon's interests are mostly in the form of working interests and volumetric production payments, and, to a lesser extent, overriding royalty, foreign government concessions, mineral and net profits interests and other forms of direct and indirect ownership in oil and gas properties.

PROVED RESERVES AND ESTIMATED FUTURE NET REVENUE

"Proved reserves" are those quantities of oil, natural gas and NGLs, which geological and engineering data demonstrate with reasonable certainty to be recoverable in the future from known reservoirs under existing economic and operating conditions. All reserve estimates were prepared using standard geological and engineering methods generally accepted by the petroleum industry and in accordance with SEC definitions and guidelines (as described in the following notes). The following table sets forth Devon's estimated proved reserves, the estimated future net revenues therefrom and the 10% Present Value thereof as of December 31, 2001. Approximately 67% of Devon's U.S. proved reserves were estimated by LaRoche Petroleum Consultants, Ltd. and Ryder Scott Company Petroleum Consultants, independent petroleum consultants. Devon's internal staff of engineers estimated the remainder of the U.S. reserves. Approximately 43% of the year-end 2001 Canadian proved reserves were calculated by the independent petroleum consultants of Paddock Lindstrom & Associates and Gilbert Laustsen Jung Associates, Ltd. The remaining percentage of Canadian reserves are based on Devon's own estimates. The international proved reserves, other than Canada, were calculated by the independent petroleum consultants of Ryder Scott Company Petroleum Consultants. These estimates correspond with the method used in presenting the "Supplemental Information on Oil and Gas Operations" in Note 16 to Devon's Consolidated Financial Statements included herein, except that federal income taxes attributable to such future net revenues have been disregarded in the presentation below.

16

	TOTAL PROVED RESERVES	PROVED DEVELOPED RESERVES (1)
TOTAL RESERVES		
Oil (MMBbls)	586	324
Gas (Bcf)	5,477	3,948
NGL (MMBbls)	121	88
MMBoe (3)	1,620	1,070
Pre-tax Future Net Revenue ($ millions)(4)	13,138	8,707
Pre-tax 10% Present Value ($ millions)(4)	7,174	5,800
Standardized measure of discounted future net cash flows ($ millions)(5)	5,314	
U.S. RESERVES		
Oil (MMBbls)	191	167
Gas (Bcf)	2,399	1,988
NGL (MMBbls)	52	48
MMBoe (3)	642	545
Pre-tax Future Net Revenue ($ millions)(4)	5,294	4,663
Pre-tax 10% Present Value ($ millions)(4)	3,270	2,952
Standardized measure of discounted future net cash flows ($ millions)(5)	2,801	

CANADIAN RESERVES		
Oil (MMBbls)	166	124
Gas (Bcf)	2,625	1,923
NGL (MMBbls)	56	40
MMBoe (3)	659	485
Pre-tax Future Net Revenue ($ millions)(4)	4,797	3,732
Pre-tax 10% Present Value ($ millions)(4)	2,744	2,614
Standardized measure of discounted future net cash flows ($ millions)(5)	1,596	
INTERNATIONAL RESERVES		
Oil (MMBbls)	229	33
Gas (Bcf)	453	37
NGL (MMBbls)	13	--
MMBoe (3)	319	40
Pre-tax Future Net Revenue ($ millions)(4)	3,047	312
Pre-tax 10% Present Value ($ millions)(4)	1,160	234
Standardized measure of discounted future net cash flows ($ millions)(5)	917	

(1) Proved developed reserves are proved reserves that are expected to be recovered from existing wells with existing equipment and operating methods.

(2) Proved undeveloped reserves are proved reserves to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompleting or deepening a well or for new fluid injection facilities.

(3) Gas reserves are converted to MMBoe at the rate of six Mcf per Bbl of oil, based upon the approximate relative energy content of natural gas to oil, which rate is not necessarily indicative of the relationship of gas to oil prices. The respective prices of gas and oil are affected by market conditions and other factors in addition to relative energy content.

17

(4) Estimated future net revenue represents estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and development costs. The amounts shown do not give effect to non-property related expenses such as general and administrative expenses, debt service and future income tax expense or to depreciation, depletion and amortization.

These amounts were calculated using prices and costs in effect as of December 31, 2001. These prices were not changed except where different prices were fixed and determinable from applicable contracts. These assumptions yield average prices over the life of Devon's properties of $16.54 per Bbl of oil, $2.28 per Mcf of natural gas and $13.21 per Bbl of NGLs. These prices compare to December 31, 2001, New York Mercantile Exchange prices of $19.84 per Bbl for crude oil and of $2.65 per MMBtu for natural gas.

(5) See Note 16 to the consolidated financial statements included in Item 8 of this report.

No estimates of Devon's proved reserves have been filed with or included in reports to any federal or foreign governmental authority or agency since the beginning of the last fiscal year except (i) in filings with the SEC and (ii) in filings with the Department of Energy ("DOE"). Reserve estimates filed by Devon with the SEC correspond with the estimates of Devon reserves contained herein. Reserve estimates filed with the DOE are based upon the same underlying technical and economic assumptions as the estimates of Devon's reserves included herein. However, the DOE requires reports to include the interests of all owners in wells that Devon operates and to exclude all interests in wells that Devon does not operate.

The prices used in calculating the estimated future net revenues attributable to proved reserves do not necessarily reflect market prices for oil, gas and NGL production subsequent to December 31, 2001. There can be no assurance that all of the proved reserves will be produced and sold within the periods indicated, that the assumed prices will be realized or that existing contracts will be honored or judicially enforced.

The process of estimating oil, gas and NGLs reserves is complex, requiring significant subjective decisions in the evaluation of available geological, engineering and economic data for each reservoir. The data for a given reservoir may change substantially over time as a result of, among other things, additional development activity, production history and viability of production under varying economic conditions. Consequently, material revisions to existing reserve estimates may occur in the future.

PRODUCTION, REVENUE AND PRICE HISTORY

Certain information concerning oil and natural gas production, prices, revenues (net of all royalties, overriding royalties and other third party interests) and operating expenses for the three years ended December 31, 2001, is set forth in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations."

WELL STATISTICS

The following table sets forth Devon's producing wells as of December 31, 2001:

	Oil Wells		Gas Wells		Total Wells	
	Gross (1)	Net (2)	Gross (1)	Net (2)	Gross (1)	N
U.S.	8,610	4,054	9,224	4,591	17,834	
Canada	6,999	3,205	6,998	4,038	13,997	
International	1,393	397	75	25	1,468	
Total	17,002	7,656	16,297	8,654	33,299	

(1) Gross wells are the total number of wells in which Devon owns a working interest.

(2) Net refers to gross wells multiplied by Devon's fractional working interests therein.

Devon also held numerous overriding royalty interests in oil and gas wells, a portion of which are convertible to working interests after recovery of certain costs by third parties. After converting to working interests, these overriding royalty interests will be included in Devon's gross and net well count.

UNDEVELOPED ACREAGE

The following table sets forth Devon's developed and undeveloped oil and gas lease and mineral acreage as of December 31, 2001.

	Developed		Unde
	Gross (1)	Net (2)	Gross (1)
United States		(In Thousands)	
Permian/Mid-Continent Division			
Permian Basin	780	383	1,270
Mid-Continent	698	432	1,664
Total Permian/Mid-Continent Division	1,478	815	2,934
Rocky Mountain Division	576	308	1,962
Gulf Division			
Offshore	638	333	903
Onshore	389	220	153
Total Gulf Division	1,027	553	1,056
Total U.S.	3,081	1,676	5,952
Canada	4,032	2,486	15,378
International	495	209	14,846
Grand Total	7,608	4,371	36,176

(1) Gross acres are the total number of acres in which Devon owns a working interest.

(2) Net refers to gross acres multiplied by Devon's fractional working interests therein.

19

OPERATION OF PROPERTIES

The day-to-day operations of oil and gas properties are the responsibility of an operator designated under pooling or operating agreements. The operator supervises production, maintains production records, employs field personnel and performs other functions. The charges under operating agreements customarily vary with the depth and location of the well being operated.

Devon is the operator of 16,478 of its wells. As operator, Devon receives reimbursement for direct expenses incurred in the performance of its duties as well as monthly per-well producing and drilling overhead reimbursement at rates customarily charged in the area to or by unaffiliated third parties. In presenting its financial data, Devon records the monthly overhead reimbursements as a reduction of general and administrative expense, which is a common industry practice.

ORGANIZATION STRUCTURE

Devon's properties are distributed geographically in five separate divisions. Operations in the United States are focused in the Permian/Mid-Continent, the Rocky Mountain and Gulf divisions. Canadian operations are focused in the Western Canadian Sedimentary Basin in Alberta and British Columbia. All operations outside North America make up Devon's International division. Maintaining a tight geographic focus in selected core areas is a key element of Devon's operating strategy. This concentration has allowed Devon to improve operating and capital efficiency.

UNITED STATES PROPERTIES

PERMIAN/MID-CONTINENT DIVISION

Devon's Permian/Mid-Continent Division includes portions of New Mexico, Texas, Oklahoma, Kansas, Mississippi and Louisiana. This area encompasses a wide variety of geologic formations and productive depths. The Permian/Mid-Continent produces more oil than any other division in the company and a significant portion of Devon's natural gas. Devon's Permian/Mid-Continent production has historically come from conventional oil and gas properties. However, Devon recently established dominant positions in two non-conventional gas plays in the Permian/Mid-Continent: the Barnett Shale and the Cherokee coalbed methane project.

The most significant asset brought to Devon in its January 24, 2002 acquisition of Mitchell Energy is the interest in the Barnett Shale of north Texas. The Barnett Shale is known as a "tight gas" formation. This means that in its natural state, the formation is resistant to the production of natural gas. Mitchell spent decades understanding how to efficiently develop and produce this gas. The resulting technology yielded a low-risk and highly profitable natural gas play. Devon holds 525,000 net acres and over 800 producing wells in the Barnett Shale. Devon's average working interest is approximately 95%. The Barnett Shale is a unique, unconventional gas resource that offers immediate low-risk production growth and the potential for significant reserve additions.

20

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

In 2002, Devon plans to drill 300 new Barnett Shale wells and refracture 144 wells. The Company also plans to drill eight exploratory wells outside the core development area with the hope of expanding the productive area. The Barnett Shale is expected to be an important growth area for Devon for many years to come.

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

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

ROCKY MOUNTAIN DIVISION

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

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

Plans call for drilling more than 200 Powder River wells in 2002. This will include

21

roughly 170 wells in existing producing areas and 90 wells in new project areas. Current production is primarily from the Wyodak coal formation. In addition, the Company has several new projects developing the deeper Big George coals. Success in the Big George would significantly expand the potential of Devon's 250,000 net acres in this area.

GULF DIVISION

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

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

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

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

A further source of oil and gas reserves and production growth lies in the Gulf Coast region onshore South Texas. Devon's activities in this area have focused on exploration in the Edwards, Wilcox and Frio/Vicksberg trends. In 2001 Devon drilled five successful exploration

22

wells and 32 development wells. As a result, over the course of the year Devon's share of production doubled to more than 60 million cubic feet per day. The Mitchell acquisition, completed in early 2002, adds additional production and undeveloped acreage in the South Texas area. With a large, high-quality inventory of additional drilling locations, we expect South Texas to be a source of continued growth.

CANADA

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

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

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

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

Near the end of 2002, Devon plans to bring several previous deep gas discoveries on stream in the Grizzly Valley area of the Foothills of northeastern British Columbia. Since its initial discovery here in 1998, Devon has drilled 11 successful wells. Devon expects to commence initial production at a combined rate of about 50 million cubic feet of gas per day to Devon.

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

One of the highest potential exploration assets Devon acquired from Anderson was its 1.5

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

INTERNATIONAL

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

In Azerbaijan, Devon holds a 5.6% carried interest in a world-class oil development project, the Azeri-Chirag-Gunashli Field. Significant production from this multi-billion barrel oilfield is still several years away pending completion of an additional export pipeline. In China, Devon is the largest acreage holder in the Pearl River Mouth Basin in the South China Sea. Development of our Panyu Project is underway and Devon expects first oil production from two offshore platforms in late 2003. Devon expects its share of production to approximate 15,000 barrels per day.

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

SIGNIFICANT PROPERTIES

The following table sets forth proved reserve information on the most significant geographic areas in which Devon's properties are located as of December 31, 2001.

	OIL (MMBBLS)	GAS (BCF)	NGLS (MMBBLS)	MMBOE (1)	MMBOE % (2)	10% PRESENT VALUE (IN MILLIONS
UNITED STATES						
PERMIAN/MID-CONTINENT						
Permian Basin	117	346	15	189	11.6%	$ 960
Mid-Continent	9	562	18	121	7.5%	659
Total	126	908	33	310	19.1%	1,619
ROCKY MOUNTAIN						
Total	24	1,114	9	219	13.5%	859
GULF						
Offshore	37	275	8	90	5.6%	639
Onshore	4	102	2	23	1.4%	153
Total	41	377	10	113	7.0%	792
TOTAL U.S.	191	2,399	52	642	39.6%	3,270
CANADA						
Total(4)	166	2,625	56	659	40.7%	2,744
INTERNATIONAL						
Total	229	453	13	319	19.7%	1,160
Grand Total	586	5,477	121	1,620	100.0%	$ 7,174

(1) Gas reserves are converted to MMBoe at the rate of six Mcf of gas per Bbl of oil, based upon the approximate relative energy content of natural gas to oil, which rate is not necessarily indicative of the relationship of gas to oil prices. The respective prices of gas and oil are affected by market and other factors in addition to relative energy content.

(2) Percentage which MMBoe for the basin or region bears to total MMBoe for all proved reserves.

(3) Percentages which present value for the basin or region bears to total

present value for all proved reserves.

(4) Canadian dollars converted to U.S. dollars at the rate of $1 Canadian: $0.6279 U.S.

TITLE TO PROPERTIES

Title to properties is subject to contractual arrangements customary in the oil and gas industry, liens for current taxes not yet due and, in some instances, other encumbrances. Devon believes that such burdens do not materially detract from the value of such properties or from the respective interests therein or materially interfere with their use in the operation of the business.

As is customary in the industry in the case of undeveloped properties, little investigation of record title is made at the time of acquisition (other than a preliminary review of local records). Investigations, generally including a title opinion of outside counsel, are made prior to the consummation of an acquisition of producing properties and before commencement of drilling operations on undeveloped properties.

ITEM 3. LEGAL PROCEEDINGS

Royalty Matters

Numerous gas producers and related parties, including Devon, have been named in various lawsuits filed by private litigants alleging violation of the federal False Claims Act. The suits allege

25

that the producers and related parties used below-market prices, improper deductions, improper measurement techniques and transactions with affiliates which resulted in underpayment of royalties in connection with natural gas and natural gas liquids produced and sold from federal and Indian owned or controlled lands. The various suits have been consolidated by the United States Judicial Panel on Multidistrict Litigation for pre-trial proceedings in the matter of In re Natural Gas Royalties Qui Tam Litigation, MDL-1293, United States District Court for the District of Wyoming. Devon believes that it has acted reasonably, has legitimate and strong defenses to all allegations in the suits, and has paid royalties in good faith. Devon does not currently believe that it is subject to material exposure in association with these lawsuits and no liability has been recorded in connection therewith.

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

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

There were no matters submitted to a vote of security holders during the fourth quarter of 2001.

26

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

MARKET PRICE

Devon's common stock has been traded on the American Stock Exchange (the "AMEX") since September 29, 1988. Prior to September 29, 1988, Devon's common stock was privately held. Commencing on December 15, 1998, a new class of Devon exchangeable shares began trading on The Toronto Stock Exchange ("TSE") under the symbol NSX. These shares are essentially equivalent to Devon common stock. However, because they are issued by Devon's wholly-owned subsidiary, Northstar, they qualify as a domestic Canadian investment for Canadian institutional shareholders. They are exchangeable at any time, on a one-for-one basis, for common shares of Devon at the holder's option.

The following table sets forth the high and low sales prices for Devon common stock and exchangeable shares as reported by the AMEX and TSE for the periods indicated.

	American Stock Exchange			The Toronto St	
	High (US$)	Low (US$)	Average Daily Volume	High (CN$)	Lo (C
2000:					
Quarter Ended March 31, 2000	48.56	31.38	376,279	69.50	45
Quarter Ended June 30, 2000	60.94	43.75	613,910	90.10	65
Quarter Ended September 30, 2000	62.56	42.56	998,008	92.45	62
Quarter Ended December 31, 2000	64.74	48.00	829,198	97.45	73
2001:					
Quarter Ended March 31, 2001	66.75	52.30	977,648	102.85	78
Quarter Ended June 30, 2001	62.65	48.50	1,053,178	95.25	75
Quarter Ended September 30, 2001	55.25	30.55	1,582,815	84.40	49
Quarter Ended December 31, 2001	41.25	31.45	1,279,434	64.71	51

DIVIDENDS

Devon commenced the payment of regular quarterly cash dividends on its common stock on June 30, 1993, in the amount of $0.03 per share. Effective December 31, 1996, Devon increased its quarterly dividend payment to $0.05 per share. Devon anticipates continuing to pay regular quarterly dividends in the foreseeable future. Dividends are also paid on the exchangeable shares at the same rate and on the same dates as dividends paid on the common stock.

On March 14, 2002, there were 30,431 holders of record of Devon common stock and 298 holders of record for the exchangeable shares.

ITEM 6. SELECTED FINANCIAL DATA

The following selected financial information (not covered by the independent auditors' reports) should be read in conjunction with "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations," and the consolidated financial statements and the notes thereto included in "Item 8. Financial Statements and Supplementary Data." Notes 2 and 19 to the consolidated financial statements included in Item 8 of this report contain information on mergers and acquisitions which occurred in 2002, 2001, 2000 and 1999, as well as unaudited pro forma financial data for the years 2001 and 2000.

	YEAR ENDED DE		
	2001	2000	1999
	(MILLIONS, EXCEPT PER SHARE		
OPERATING RESULTS			
Oil sales	$ 958	1,079	561
Gas sales	1,890	1,485	628
NGL sales	132	154	68
Other revenue	95	66	21
Total revenues	3,075	2,784	1,278
Lease operating expenses	531	441	299
Transportation costs	83	53	34
Production taxes	117	103	45
Depreciation, depletion and amortization of property and equipment	876	693	406
Amortization of goodwill	34	41	16
General and administrative expenses	111	93	81
Expenses related to mergers	1	60	17
Interest expense	220	155	109
Effects of changes in foreign currency exchange rates	13	3	(13)
Distributions on preferred securities of subsidiary trust	--	--	7
Change in fair value of financial instruments	2	--	--
Reduction of carrying value of oil and gas properties	1,003	--	476
Total costs and expenses	2,991	1,642	1,477
Earnings (loss) before income taxes, minority interest, extraordinary item and cumulative effect of change in accounting principle	84	1,142	(199)
Income tax expense (benefit):			
Current	71	131	23
Deferred	(41)	281	(72)
Total	30	412	(49)
Earnings (loss) before minority interest, extraordinary item and cumulative effect of change in accounting principle	54	730	(150)
Minority interest in Monterey Resources, Inc.		--	--
Earnings (loss) before extraordinary item and cumulative effect of change in accounting principle	54	730	(150)
Extraordinary loss	--	--	(4)
Earnings (loss) before cumulative effect of change in accounting principle	54	730	(154)
Cumulative effect of change in accounting principle	49	--	--
Net earnings (loss)	$ 103	730	(154)
Net earnings (loss) applicable to common shareholders	$ 93	720	(158)

Net earnings (loss) per share before extraordinary loss and cumulative effect of change in accounting principle:			
Basic	$ 0.34	5.66	(1.64)
Diluted	$ 0.34	5.50	(1.64)
Net earnings (loss) per share before cumulative effect of change in accounting principle:			
Basic	$ 0.34	5.66	(1.68)
Diluted	$ 0.34	5.50	(1.68)
Net earnings (loss) per share:			
Basic	$ 0.73	5.66	(1.68)
Diluted	$ 0.72	5.50	(1.68)
Cash dividends per common share(1)	$ 0.20	0.17	0.14
Weighted average common shares outstanding:			
Basic	128	127	94
Diluted	130	132	99
Ratio of earnings to combined fixed charges and preferred stock dividends(2)	1.28	7.39	N/A

28

	DECEMBER 31		
	2001	2000	1999
			(MILLIONS)
BALANCE SHEET DATA			
Total assets	$ 13,184	6,860	6,096
Debentures exchangeable into shares of ChevronTexaco Corporation common stock	$ 649	760	760
Other long-term debt	$ 5,940	1,289	1,656
Convertible preferred securities of subsidiary trust	$ --	--	--
Stockholders' equity	$ 3,259	3,277	2,521

	YEAR ENDED DECEMBER		
	2001	2000	1999
	(MILLIONS, EXCEPT PER UNI		
CASH FLOW DATA			
Net cash provided by operating activities	$ 1,886	1,619	532
Net cash used in investing activities	$ (5,285)	(1,173)	(768)
Net cash provided by (used in) financing activities	$ 3,370	(390)	377
Modified EBITDA(3,5)	$ 2,232	2,034	802
Cash margin(4,5)	$ 1,941	1,748	663
PRODUCTION, PRICE AND OTHER DATA			
Production:			
Oil (MMBbls)	44	43	32

Gas (Bcf)	498	426	304
NGL (MMBbls)	8	7	5
MMBoe(6)	135	121	88
Average prices:			
Oil (Per Bbl)	$ 21.57	25.35	17.67
Gas (Per Mcf)	$ 3.80	3.49	2.06
NGL (Per Bbl)	$ 16.98	20.87	13.30
Per Boe(6)	$ 22.05	22.47	14.35
Costs per Boe (6):			
Operating costs	$ 5.41	4.94	4.31
Depreciation, depletion and amortization of oil and gas properties	$ 6.20	5.48	4.46
General and administrative expenses	$ 0.82	0.77	0.92

----

(1) Cash dividends per share are presented based on the combined amount of dividends paid by Devon, Santa Fe Snyder and Northstar in each year. The dividends per share are also based on the number of shares outstanding in each year assuming the Santa Fe Snyder merger and the Northstar combination had been consummated as of the beginning of the earliest year presented. Santa Fe Snyder did not pay any dividends in any of the years presented. Northstar did not pay any dividends in 1997, or in 1998 prior to the closing of the Northstar combination. Because of these facts, the cash dividends per share presented for 1997 through 2000 are not representative of the actual amounts paid by Devon on an historical basis. For the years 1997 through 2000, Devon's historical cash dividends per share were $0.20 in each year.

(2) For purposes of calculating the ratio of earnings to combined fixed charges and preferred stock dividends, (i) earnings consist of earnings before income taxes, plus fixed charges; (ii) fixed charges consist of interest expense, distributions on preferred securities of subsidiary trust, amortization of costs relating to indebtedness and the preferred securities of subsidiary trust, and one-third of rental expense estimated to be attributable to interest; and (iii) preferred stock dividends consist of the amount of pre-tax earnings required to pay dividends on the outstanding preferred stock. For the years 1999, 1998 and 1997, earnings were insufficient to cover combined fixed charges and preferred stock dividends by $205 million, $362 million and $346 million, respectively.

(3) Modified EBITDA represents earnings before interest (including effects of changes in foreign currency exchange rates, change in fair value of financial instruments, and distributions on preferred securities of subsidiary trust), taxes, depreciation, depletion and amortization and reduction of carrying value of oil and gas properties.

(4) "Cash margin" equals total revenues less cash expenses. Cash expenses are all expenses other than the non-cash expenses of depreciation, depletion and amortization, effects of changes in foreign currency exchange rates, change in fair value of financial instruments, reduction of carrying value of oil and gas properties and

29

deferred income tax expense (benefit). Cash margin measures the net cash which is generated by a company's operations during a given period, without regard to the period such cash is actually physically received or spent by the company. This margin ignores the non-operational effect on a company's "net cash provided by operating activities", as measured by accounting principles generally accepted in the United States of America, from a company's activities as an operator of oil and gas wells. Such activities produce net increases or decreases in temporary cash funds held by the operator which have no effect on net earnings of the company.

(5) Modified EBITDA is presented because it is commonly accepted in the oil and gas industry as a financial indicator of a company's ability to service or incur debt. Cash margin is presented because it is commonly accepted in the oil and gas industry as a financial indicator of a company's ability to fund capital expenditures or service debt. Modified EBITDA and cash margin are also presented because investors routinely request such information. Management interprets the trends of modified EBITDA and cash margin in a similar manner as trends in net earnings.

Modified EBITDA and cash margin should be used as supplements to, and not as substitutes for, net earnings and net cash provided by operating activities determined in accordance with accounting principles generally accepted in the United States of America as measures of Devon's profitability or liquidity. There may be operational or financial demands and requirements that reduce management's discretion over the use of modified EBITDA and cash margin. See "Management's Discussion and Analysis of Financial Condition and Results of Operations." Modified EBITDA and cash margin may not be comparable to similarly titled measures used by other companies.

(6) Gas volumes are converted to Boe or MMBoe at the rate of six Mcf of gas per barrel of oil, based upon the approximate relative energy content of natural gas and oil, which rate is not necessarily indicative of the relationship of oil and gas prices. The respective prices of oil, gas and NGLs are affected by market and other factors in addition to relative energy content.

30

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion and analysis addresses changes in Devon's financial condition and results of operations during the three year period of 1999 through 2001. Reference is made to "Item 6. Selected Financial Data" and "Item 8. Financial Statements and Supplementary Data."

OVERVIEW

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

Following the Mitchell merger announcement, Devon announced on September 4, 2001, that it had entered into an agreement to acquire Anderson Exploration Ltd. ("Anderson") for approximately $3.5 billion in cash. This acquisition closed on October 15, 2001, and therefore had an impact on Devon's results for the last two and one-half months of the year.

To fund the cash portions of these two acquisitions, as well as to pay related transaction costs and retire certain long-term debt assumed from

Mitchell and Anderson, Devon entered into long-term debt agreements in October 2001 that totaled $6 billion. As part of this $6 billion total, Devon issued $3 billion of notes and debentures on October 3, 2001. Of this total, $1.25 billion bears interest at 7.875% and matures in September 2031. The remaining $1.75 billion bears interest at 6.875% and matures in September 2011.

The remaining $3 billion of the $6 billion of long-term debt is in the form of a credit facility that bears interest at floating rates. At December 31, 2001, $1 billion of this facility was borrowed. Following the close of the Mitchell transaction, the $3 billion facility was fully borrowed. Principal payments due on this debt are $0.2 billion in October 2004, $1.2 billion in 2005 and $1.6 billion in 2006. The 2005 and 2006 payments are split equally in payments due in April and October of those years. The interest rate on this debt at December 31, 2001 was 2.9%.

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

In addition to the mergers and acquisitions, Devon's exploration and development efforts have also been significant contributors to Devon's growth. In 1999, before the merger with Santa Fe Snyder, Devon spent approximately $301 million in its exploration, drilling and development efforts. These costs included drilling 678 wells, of which 636 were completed as producers. In 2000, Devon and Santa Fe Snyder combined spent $904 million in its exploration, drilling and development

efforts. These costs included drilling 1,328 wells, of which 1,261 were completed as producers. In 2001, Devon spent $2.9 billion in its exploration, drilling and development efforts. These costs included drilling 1,545 wells, of which 1,444 were completed as producers, and acquiring $1.4 billion of unproved leasehold in the Anderson acquisition.

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

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

- Combined oil, gas and NGL production increased 82 million Boe, or 155%.

- Average combined price of oil, gas and NGLs increased by $8.43 per Boe, or 62%.

- Total revenues increased $2.3 billion, or 319%.

- Net cash provided by operating activities increased $1.7 billion, or 816%. Cash margin increased $1.5 billion, or 395%.

During 2001, Devon marked its 13th anniversary as a public company. While Devon has consistently increased production over this 13-year period, volatility in oil and gas prices has resulted in considerable variability in earnings and cash flows. Prices for oil, natural gas and NGLs are determined primarily by market conditions. Market conditions for these products have been, and will continue to be, influenced by regional and worldwide economic growth, weather and other factors that are beyond Devon's control. Devon's future earnings and cash flows will continue to depend on market conditions.

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

32

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

Because oil and gas prices are influenced by many factors outside of its control, Devon's management has focused its efforts on increasing oil and gas reserves and production and controlling expenses. Over its 13-year history as a public company, Devon has been able to reduce its controllable operating costs per unit of production. Devon's future earnings and cash flows are dependent on its ability to continue to contain operating costs at levels that allow for profitable production.

RESULTS OF OPERATIONS

The following discussion of Devon's results of operations from 1999 through 2001 include the restated results of Devon for the 2000 merger with Santa Fe Snyder which was accounted for using the pooling-of-interests method.

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

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

	TOTAL				
	YEAR ENDED DECEMBER 31,				
	2001	2001 vs 2000	2000	2000 vs 1999	1999

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

33

DOMESTIC

YEAR ENDED DECEMBER 31,

	2001	2001 vs 2000	2000	2000 vs 1999	1999
PRODUCTION					
Oil (MMBbls)	26	-10%	29	+61%	18
Gas (Bcf)	376	+6%	355	+61%	221
NGLs (MMBbls)	6	+0%	6	+50%	4
Oil, gas and NGLs (MMBoe)	95	+1%	94	+59%	59
REVENUES					
Per Unit of Production:					
Oil (per Bbl)	$22.36	-12%	25.45	+37%	18.64
Gas (per Mcf)	$ 4.17	+14%	3.67	+62%	2.27
NGLs (per Bbl)	$17.15	-16%	20.30	+55%	13.11
Oil, gas and NGLs (per Boe)	$23.80	+4%	22.95	+52%	15.10
Absolute (in millions):					
Oil	$ 586	-19%	727	+119%	332
Gas	$1,571	+20%	1,305	+160%	502
NGLs	$ 103	-24%	136	+134%	58
Oil, gas and NGLs	$2,260	+4%	2,168	+143%	892

	CANADA				
	YEAR ENDED DECEMBER 31,				
	2001	2001 vs 2000	2000	2000 vs 1999	1999
PRODUCTION					
Oil (MMBbls)	8	+60%	5	+0%	5
Gas (Bcf)	113	+82%	62	-16%	74
NGLs (MMBbls)	2	+100%	1	+0%	1
Oil, gas and NGLs (MMBoe)	29	+81%	16	-11%	18
REVENUES					
Per Unit of Production:					
Oil (per Bbl)	$17.84	-27%	24.46	+58%	15.51
Gas (per Mcf)	$ 2.73	+1%	2.71	+75%	1.55
NGLs (per Bbl)	$16.43	-38%	26.51	+84%	14.39
Oil, gas and NGLs (per Boe)	$16.80	-12%	19.18	+70%	11.27
Absolute (in millions):					
Oil	$ 146	+26%	116	+45%	80
Gas	$ 307	+82%	169	+48%	114
NGLs	$ 28	+56%	18	+80%	10
Oil, gas and NGLs	$ 481	+59%	303	+49%	204

34

	INTERNATIONAL				
	YEAR ENDED DECEMBER 31,				
	2001	2001 vs 2000	2000	2000 vs 1999	1999
PRODUCTION					
Oil (MMBbls)	10	+11%	9	+0%	9
Gas (Bcf)	9	+0%	9	+0%	9
NGLs (MMBbls)	--	N/M	--	N/M	--
Oil, gas and NGLs (MMBoe)	11	+0%	11	+0%	11
REVENUES					
Per Unit of Production:					
Oil (per Bbl)	$22.57	-11%	25.48	+50%	16.96
Gas (per Mcf)	$ 1.41	+7%	1.32	+6%	1.24
NGLs (per Bbl)	$16.15	-24%	21.19	+6%	20.00
Oil, gas and NGLs (per Boe)	$20.76	-10%	23.08	+49%	15.50
Absolute (in millions):					
Oil	$ 226	-4%	236	+58%	149
Gas	$ 12	+9%	11	-8%	12
NGLs	$ 1	N/M	--	N/M	--
Oil, gas and NGLs	$ 239	-3%	247	+53%	161

====== ====== ======

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

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

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

2000 vs. 1999 Oil revenues increased $518 million in 2000. Of this total increase, $327 million was due to a $7.68 per barrel increase in the average price of oil in 2000. An increase in production of 11 million barrels caused the remaining $191 million of increased revenues. The PennzEnergy merger accounted for seven million barrels of the 11 million barrel increase. The year 2000 included 12 months of production from the properties acquired in the 1999 PennzEnergy merger, while 1999 only included production for four and one-half months following the August 17, 1999 merger closing. The remaining four million barrel increase in 2000's production was

35

caused by drilling activity and other acquisitions, offset in part by property dispositions and natural declines.

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

A $0.31 per Mcf increase in the average gas price in 2001 accounted for the remaining $156 million of increased gas revenues.

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

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

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

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

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

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

36

	YEAR ENDED DECEMBER 31,			
	2001	2001 vs 2000	2000	2000 vs 1999
Absolute (in millions):				
Production and operating expenses:				
Lease operating expenses	$ 531	+20%	441	+47%
Transportation costs	83	+57%	53	+56%
Production taxes	117	+14%	103	+129%
Depreciation, depletion and amortization of oil and gas properties	838	+26%	663	+70%
Amortization of goodwill	34	-17%	41	+156%
Subtotal	1,603	+23%	1,301	+66%
Depreciation and amortization of non-oil and gas properties	38	+27%	30	+88%
General and administrative expenses	111	+19%	93	+15%
Expenses related to mergers	1	-98%	60	+253%
Interest expense	220	+42%	155	+42%
Effects of changes in foreign currency Exchange rates	13	+333%	3	-123%
Change in fair value of				

Financial instruments	2	N/M	--	N/M
Distributions on preferred securities of Subsidiary trust	--	N/M	--	-100%
Reduction of carrying value of oil and gas Properties	1,003	N/M	--	-100%
Total	$ 2,991	+82%	1,642	+11%
Per Boe:				
Production and operating expenses:				
Lease operating expenses	$ 3.93	+8%	3.65	+7%
Transportation costs	0.61	+39%	0.44	+13%
Production taxes	0.87	+2%	0.85	+67%
Depreciation, depletion and amortization of oil and gas properties	6.20	+13%	5.48	+23%
Amortization of goodwill	0.25	-26%	0.34	+89%
Subtotal	11.86	+10%	10.76	+20%
Depreciation and amortization of non-oil and gas properties (1)	0.28	+12%	0.25	+32%
General and administrative expenses (1)	0.82	+6%	0.77	-16%
Expenses related to mergers (1)	0.01	-98%	0.50	+163%
Interest expense (1)	1.63	+28%	1.27	+2%
Effects of changes in foreign currency Exchange rates (1)	0.09	+350%	0.02	N/M
Change in fair value of financial Instruments (1)	0.02	N/M	--	N/M
Distributions on preferred securities of Subsidiary trust (1)	--	N/M	--	-100%
Reduction of carrying value of oil and gas Properties (1)	7.43	N/M	--	-100%
Total	$ 22.14	+63%	13.57	-20%

(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 1999 and 2001 are shown in the table below.

	YEAR ENDED DECEMBER 31,				
	2001	2001 vs 2000	2000	2000 vs 1999	199
Absolute (in millions):					
Recurring lease operating expenses	$ 513	+21%	423	+45%	2
Well workover expenses	18	+0%	18	+125%	
Transportation costs	83	+57%	53	+56%	

Production taxes	117	+14%	103	+129%	
Total production and operating expenses	$ 731	+22%	597	+58%	3
Per Boe:					
Recurring lease operating expenses	$ 3.79	+8%	3.50	+5%	3.
Well workover expenses	0.14	-7%	0.15	+67%	0.
Transportation costs	0.61	+39%	0.44	+13%	0.
Production taxes	0.87	+2%	0.85	+67%	0.
Total production and operating expenses	$ 5.41	+10%	4.94	+15%	4.

2001 vs. 2000 Recurring lease operating expenses increased $90 million in 2001. The Anderson acquisition accounted for $47 million of the increase in expenses. The remaining increase in recurring costs was primarily caused by higher third-party service, fuel and electricity costs as well as increased production.

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

The majority of Devon's production taxes are assessed on its onshore domestic properties. In the U.S., most of the production taxes are based on a fixed percentage of revenues. Therefore, the 4% increase in domestic oil, gas and NGL revenues was the primary cause of a 11% increase in domestic production taxes. Production taxes did not increase proportionately to the increase in revenues. This was primarily due to the fact that most of the change in domestic revenues occurred in the Rocky Mountain division which has higher production tax rates than the other domestic divisions.

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

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

38

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

DEPRECIATION, DEPLETION AND AMORTIZATION ("DD&A") Devon's 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 and dismantlement and abandonment costs (the "depletable base"). Generally, if reserve volumes are revised up or down, then the DD&A rate per unit of production will change inversely. However, if the depletable base changes, then the DD&A rate moves in the same direction. The per unit DD&A rate is not affected by production volumes. Absolute or total DD&A, as opposed to the rate per unit of production, generally moves in the same direction as production volumes. Oil and gas property DD&A is calculated separately on a country-by-country basis.

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

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

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

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

GENERAL AND ADMINISTRATIVE EXPENSES ("G&A") Devon's net G&A consists of three primary components. The largest of these components is the gross amount of expenses incurred for personnel costs, office expenses, professional fees and other G&A items. The gross amount of these expenses is partially reduced by two offsetting components. One is the amount of G&A capitalized pursuant to the full cost method of accounting. The other is the amount of G&A reimbursed by working interest owners of properties for which Devon serves as the operator. These reimbursements are received during both the drilling and operational stages of a property's life. The gross amount of G&A incurred, less the amounts capitalized and reimbursed, is recorded as net G&A in the consolidated statements of operations. See the following table for a summary of G&A expenses by component.

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

2001 vs. 2000 Net G&A increased $18 million in 2001. Gross G&A increased $39 million primarily due to additional costs incurred as a result of the Anderson acquisition and additional personnel related costs. G&A was reduced $15 million in 2001 due to an increase in the amount capitalized as part of oil and gas properties. The increase in capitalized G&A was primarily related to additional personnel related costs and increased acquisition, exploration and development activities. G&A was also reduced $6 million by an increase in the amount of reimbursements on operated properties. The increase in reimbursed G&A was primarily related to an increase in the number of operated properties.

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

EXPENSES RELATED TO MERGERS Approximately $1 million of expenses were incurred in 2001 in connection with the Anderson acquisition. These costs related to Devon employees who were terminated as part of the Anderson acquisition.

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

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

INTEREST EXPENSE 2001 vs. 2000 Interest expense increased $65 million in 2001. Of this total increase, $44 million was caused by an increase in the average debt balance outstanding from $2.3 billion in 2000 to $3.0 billion in 2001. The increase in average debt outstanding was

40

attributable primarily to the long-term debt issued as a result of the October 2001 Anderson acquisition.

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

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

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

The average interest rate on outstanding debt decreased from 7% in 1999 to 6.7% in 2000. This rate decrease caused interest expense to decrease $5 million in 2000. Other items included in interest expense that are not related to the debt balance outstanding, such as facility and agency fees, amortization of costs and other miscellaneous items, were $3 million lower in 2000 compared to 1999.

EFFECTS OF CHANGES IN FOREIGN CURRENCY EXCHANGE RATES 2001 vs. 2000 As a result of the Anderson acquisition, Devon's Canadian subsidiary, Devon Canada Corporation, assumed certain fixed-rate senior notes which are denominated in U.S. dollars. Changes in the exchange rate between the U.S. dollar and the Canadian dollar from the dates the notes were acquired to the dates of repayment increase or decrease the expected amount of Canadian dollars eventually required to repay the notes. Such changes in the Canadian dollar equivalent balance of the debt are required to be included in determining net earnings for the period in which the exchange rate changes. The drop in the Canadian-to-U.S. dollar exchange rate from $0.642 at October 15, 2001 to $0.628 at December 31, 2001 resulted in an $11 million loss. Additionally, the devaluation of the Argentine peso resulted in a $2 million loss in 2001.

41

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

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

REDUCTION OF CARRYING VALUE OF OIL AND GAS PROPERTIES Under the full cost method of accounting, the net book value of oil and gas properties, less related deferred income taxes, may not exceed a calculated "ceiling." The ceiling limitation is the discounted estimated after-tax future net revenues from proved oil and gas properties plus the lower of cost or fair value of unproved properties. The ceiling is imposed separately by country. In calculating future net revenues, current prices and costs are generally held constant indefinitely. The net book value, less related 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.

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

	YEAR ENDED DECEMBER 31,			
	2001		1999	
	Gross	Net of Taxes	Gross	Net of Taxes
	(IN MILLIONS)			
United States	$449	281	464	302
Canada	434	252	--	--
Egypt	33	23	--	--
China	--	--	12	8
Total	$916	556	476	310

The 2001 domestic and Canadian reductions were primarily the result of lower prices. Under the purchase method of accounting for business combinations, acquired oil and gas properties are recorded at fair value as of the date of purchase. Devon estimates such fair value using its estimates of future oil and gas prices. In contrast, the ceiling calculation dictates that prices in effect as of the last day of the applicable quarter are held constant indefinitely. Accordingly, the resulting value is not indicative of the true fair value of the reserves. The oil and gas properties added from the Anderson acquisition and other smaller acquisitions in 2001 were recorded at fair values that were based on expected future oil and gas prices higher than the

year-end 2001 prices used to calculate the ceiling. The reduction in Egypt was the result of high finding and development costs and negative revisions to proved reserves.

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

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

INCOME TAXES 2001 vs. 2000 Devon's 2001 and 2000 effective financial tax expense rates were 36% each year. The 2001 rate was higher than the statutory federal tax rate of 35% due to the effect of state taxes, goodwill amortization that was not deductible for income tax purposes and the effect of foreign income taxes. The 2000 rate was higher than the statutory federal tax rate due to the effect of state taxes, goodwill amortization that was not deductible for income tax purposes and the effect of foreign income taxes, offset in part by the recognition of a benefit from the disposition of Devon's assets in Venezuela.

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

CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE At the time of adoption of SFAS No. 133, Devon recorded a cumulative-effect-type adjustment to net earnings for a $49.5 million gain related to the fair value of derivatives that do not qualify as hedges. This gain included $46.2 million related to the option embedded in the debentures that are exchangeable into shares of ChevronTexaco Corporation common stock.

CAPITAL EXPENDITURES, CAPITAL RESOURCES AND LIQUIDITY

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

CAPITAL EXPENDITURES Approximately $5.3 billion was spent in 2001 for capital expenditures, of which $5.2 billion was related to the acquisition, drilling or development of oil and gas properties. These amounts compare to 2000 total expenditures of $1.3 billion ($1.2 billion of which was related to oil and gas properties) and 1999 total expenditures of $0.9 billion ($0.8 billion of which was related to oil and gas properties.)

43

OTHER CASH USES Devon's common stock dividends were $25 million, $22 million and $13 million in 2001, 2000 and 1999, respectively. Devon also paid $10 million of preferred stock dividends in 2001 and 2000 and $4 million in the last four and one-half months of 1999 following the PennzEnergy merger.

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

CAPITAL RESOURCES AND LIQUIDITY Devon's primary source of liquidity has historically been net cash provided by operating activities ("operating cash flow"). This source has been supplemented as needed by accessing credit lines and commercial paper markets and issuing equity securities and long-term debt securities. In 2002, another major source of liquidity will be sales of oil and gas properties.

Devon's operating cash flow is sensitive to many variables, the most volatile of which is pricing of the oil, natural gas and NGLs produced. Prices for these commodities are determined primarily by prevailing market conditions. Regional and worldwide economic growth, weather and other substantially variable factors influence market conditions for these products. These factors are beyond Devon's control and are difficult to predict.

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

	Fixed-Price Physical Delivery Contracts	Price Swap Contracts	Price Collars	Total
Oil production (MMBbls)				
2002	2	10	7	19
Natural gas production (Bcf)				
2002	53	88	162	303
2003	26	36	126	188
2004	19	2	--	21

For the years 2005 through 2011, Devon has fixed-price physical delivery contracts covering natural gas production ranging from 13 Bcf to 19 Bcf per year. Devon also has Canadian gas volumes subject to fixed-price contracts in the years from 2012 through 2016, but the yearly volumes are less than 1 Bcf.

By removing the price volatility from the above volumes of oil and natural gas production, Devon has mitigated, but not eliminated, the potential negative effect of declining prices on its operating cash flow.

44

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

In December 2001, Devon announced that its capital expenditure budget for the year 2002 was approximately $1.5 billion. This capital budget represents the largest planned use of available operating cash flow. To a certain degree, the ultimate timing of these capital expenditures is within Devon's control. Therefore, if oil and natural gas prices decline to levels below its acceptable levels, Devon could choose to defer a portion of these planned 2002 capital expenditures until later periods to achieve the desired balance between sources and uses of liquidity.

Other sources of liquidity are Devon's revolving lines of credit. As of December 31, 2001, these credit lines totaled $1.1 billion, of which $884 million was available to Devon for future borrowings as of the end of 2001. The majority of the revolving credit lines consist of a U.S. facility of $725 million (the "U.S. Facility") and a Canadian facility of $275 million (the "Canadian Facility").

The $725 million U.S. Facility consists of a Tranche A facility of $200 million and a Tranche B facility of $525 million. The Tranche A facility matures on October 15, 2004. Devon may borrow funds under the Tranche B facility until August 12, 2002 (the "Tranche B Revolving Period"). Devon may request that the Tranche B Revolving Period be extended an additional 364 days by notifying the agent bank of such request between 30 and 60 days prior to the end of the Tranche B Revolving Period. Debt borrowed under the Tranche B facility matures two years and one day following the end of the Tranche B Revolving Period. On December 31, 2001, there was $50 million of debt outstanding under Tranche A of the $725 million U.S. Facility.

Devon may borrow funds under the $275 million Canadian Facility until

August 12, 2002 (the "Canadian Facility Revolving Period"). Devon may request that the Canadian Facility Revolving Period be extended an additional 364 days by notifying the agent bank of such request between 45 and 90 days prior to the end of the Canadian Facility Revolving Period. Debt outstanding as of the end of the Canadian Facility Revolving Period is payable in semi annual installments of 2.5% each for the following five years, with the final installment due five years and one day following the end of the Canadian Facility Revolving Period. On December 31, 2001, there were no borrowings outstanding under the Canadian Facility.

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

Amounts borrowed under the revolving credit facilities bear interest at various fixed rate options that Devon may elect for periods up to six months. Devon has historically elected a rate that is based upon LIBOR, plus a margin dictated by Devon's debt rating. Borrowings under the Canadian facility have also been made under a rate based upon the Bankers' Acceptance rate, plus

45

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

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

Devon's access to funds from its revolving credit facilities is not restricted under any "material adverse condition" clauses. It is not uncommon for credit agreements to include such clauses. These clauses can remove the obligation of the banks to fund the credit line if any condition or event would reasonably be expected to have a material and adverse effect on the borrower's financial condition, operations, properties or prospects considered as a whole, the borrower's ability to make timely debt payments, or the enforceability of material terms of the credit agreement. While Devon's $1 billion revolving credit facilities and its $3 billion term loan credit facility include covenants that require Devon to report a condition or event having a material adverse effect on the company, the obligation of the banks to fund the revolving credit facilities is not expressly conditioned on the absence of a marked adverse effect.

A portion of cash used in the Anderson and Mitchell acquisitions was provided by a $3 billion senior unsecured credit facility. This credit facility, which was entered into in October 2001, has a term of five years. The $3 billion credit facility, which was fully borrowed upon the closing of the Mitchell acquisition on January 24, 2002, will mature as follows:

(In Millions)

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

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

The terms of this $3 billion facility also provide that voluntary prepayments of the debt may be applied, at Devon's option, to the earliest scheduled maturities first. For example, if Devon were to prepay a portion of the $3 billion of debt with proceeds from property sales or other cash sources, the amount of

46

the prepayment would reduce, if so elected by Devon, the amounts otherwise due first in 2004, then 2005 and finally 2006.

Devon's $1 billion revolving credit facilities and its $3 billion term loan credit facility each contain only one material financial covenant. This covenant requires Devon to maintain a ratio of total funded debt to total capitalization of no more than 70% through June 30, 2002, and no more than 65% thereafter. The credit agreements contain definitions of total funded debt and total capitalization that include adjustments to the respective amounts reported in Devon's consolidated financial statements. Per the agreements, total funded debt excludes the debentures that are exchangeable into shares of ChevronTexaco Corporation common stock. Also, total capitalization is adjusted to add back noncash financial writedowns such as full cost ceiling property impairments or goodwill impairments.

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

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

Devon receives debt ratings from the major ratings agencies in the United

States. In determining Devon's debt rating, the agencies consider a number of items including, but not limited to, debt levels, planned asset sales, near-term and long-term production growth opportunities, capital allocation challenges and commodity pricing levels.

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

As summarized earlier in this section, Devon's cost of borrowing under its $1 billion revolving credit facilities and its $3 billion term loan facility is predicated on its corporate debt

rating. Therefore, even though a ratings downgrade would not accelerate scheduled maturities, it would adversely impact Devon's interest rate on its variable rate debt. Under the terms of the $1 billion revolving credit facilities and the $3 billion term loan credit facility, a one notch downgrade would increase Devon's borrowing rates by 22.5 basis points and 25 basis points, respectively. A ratings downgrade could also adversely impact Devon's ability to economically access future debt markets.

As of January 31, 2002, Devon is not aware of any potential ratings downgrades being contemplated by the rating agencies.

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

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

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

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

CRITICAL ACCOUNTING POLICIES

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

Below is information on what Devon believes are its critical accounting policies.

FULL COST CEILING CALCULATIONS Devon follows the full cost method of accounting for its oil and gas properties. The full cost method subjects companies to quarterly calculations of a "ceiling", or limitation on the amount of properties that can be capitalized on the balance sheet. If Devon's capitalized costs are in excess of the calculated ceiling, the excess must be written off as an expense. The ceiling limitation is imposed separately for each country in which Devon has oil and gas properties.

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

The passage of time provides more qualitative information regarding estimates of reserves, and revisions are made to prior estimates to reflect updated information. In the past four years, Devon's annual revisions to its reserve estimates have averaged approximately 3% of the previous year's estimate. However, there can be no assurance that more significant revisions will not be necessary in the future. If future significant revisions are necessary that reduce previously estimated reserve quantities, it could result in a full cost property writedown. In addition to the impact of the estimates of proved reserves on the calculation of the ceiling, estimates of proved reserves are also a significant component of the calculation of DD&A.

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

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

Devon recorded writedowns to its domestic and Canadian oil and gas properties as of December 31, 2001. The domestic properties were reduced by $449 million and the Canadian properties were reduced by $434 million. The year-end 2001 prices used to calculate the ceiling were based on a NYMEX oil price of $19.84 per barrel, and a Henry Hub gas price of $2.65 per MMBtu. If oil or gas prices at the end of future quarters drop below these year-end 2001 prices, or if Devon reduces its estimates of proved reserve quantities, further writedowns would likely occur. Also, in January 2002, Devon closed its merger with Mitchell. The oil and gas properties acquired in this transaction were recorded at their estimated fair value. The fair values were based on Devon's estimates of future oil and gas prices, and these estimated prices were higher than the year-end 2001 market prices for oil and gas. Therefore, the Mitchell properties were recorded at amounts which would have exceeded the related full cost ceiling calculation as of the end of 2001. This increases the likelihood that Devon will incur further property writedowns of its domestic oil and gas properties.

FAIR VALUES OF DERIVATIVE INSTRUMENTS The estimated fair values of Devon's derivative instruments are recorded on Devon's 2001 consolidated balance sheet. Substantially all of Devon's derivative instruments represent hedges of the price of future oil and natural gas production. Therefore, while fair values of such hedging instruments must be estimated as of the end of each reporting period, the changes in the fair values are not included in Devon's consolidated results of operations. Instead, the changes in fair value of hedging instruments are recorded directly to stockholders' equity until the hedged oil or natural gas quantities are produced.

The estimates of the fair values of Devon's hedging derivatives require substantial judgment. Devon estimates the fair values of its derivatives on a monthly basis using a discounted future cash flow technique. Devon obtains the forecasts of future NYMEX oil and gas prices from independent third parties. Many of Devon's hedges relate to regional prices other than NYMEX. Therefore, where necessary, Devon adjusts the NYMEX prices to prices at other regional delivery points using its own estimates of future differentials. The estimated future prices are compared to the prices fixed by the hedge agreements, and the resulting estimated future cash inflows or outflows over the lives of the hedges are discounted using Devon's current borrowing rates under its revolving credit facilities. These pricing and discounting variables are sensitive to market volatility as well as changes in future price forecasts, regional price differentials and interest rates.

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

BUSINESS COMBINATIONS Devon has grown substantially during recent years through acquisitions of other oil and natural gas companies. Most of these acquisitions have been accounted for using the purchase method of accounting, and recent accounting pronouncements ensure that all future acquisitions will be accounted for using the purchase method.

Under the purchase method, the acquiring company adds to its balance sheet the estimated fair values of the acquired company's assets and liabilities. Any excess of the purchase price over

50

the fair values of the tangible and intangible net assets acquired is recorded as goodwill. As of January 1, 2002, the accounting for goodwill has changed. In prior years, goodwill was amortized over its estimated useful life. As of 2002, goodwill with an indefinite useful life is no longer amortized, but instead is assessed for impairment at least annually.

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

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

Devon's estimates of future prices are applied to the estimated reserve quantities acquired to arrive at estimates of future net revenues. For estimated proved reserves, the future net revenues are then discounted using a 10% per annum rate.

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

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

Effective January 1, 2002, Devon adopted the remaining provisions of SFAS No. 142, Goodwill and Other Intangible Assets. Under SFAS No. 142, goodwill and intangible assets with indefinite useful lives are no longer amortized, but are instead tested for impairment at least annually. This will require Devon to estimate the fair values of its own assets and liabilities. Therefore, considerable judgment similar to that described above in connection with estimating the fair value of an acquired company in a business combination will be required to assess goodwill for impairment.

2002 ESTIMATES

The forward-looking statements provided in this discussion are based on management's examination of historical operating trends, the information which was used to prepare the December 31, 2001 reserve reports and other data in Devon's possession or available from third parties. Devon cautions that its future oil, natural gas and NGL production, revenues and expenses are subject to all of the risks and uncertainties normally incident to the exploration for and development and production and sale of oil and gas. These risks include, but are not limited to, price volatility, inflation or lack of availability of goods and services, environmental risks, drilling risks, regulatory changes, the uncertainty inherent in estimating future oil and gas production or reserves, and other risks as outlined below. Additionally, Devon cautions that its future gas services revenues and expenses are subject to all of the risks and uncertainties normally incident to the gas services business. These risks include, but are not limited to, price volatility, environmental risks, regulatory changes, the uncertainty inherent in estimating future processing volumes and pipeline throughput, and other risks as outlined below. Also, the financial results of Devon's foreign operations are subject to currency exchange rate risks. Additional risks are discussed below in the context of line items most affected by such risks.

SPECIFIC ASSUMPTIONS AND RISKS RELATED TO PRICE AND PRODUCTION ESTIMATES Prices for oil, natural gas and NGLs are determined primarily by prevailing market conditions. Market conditions for these products are influenced by regional and worldwide economic growth, weather and other substantially variable factors. These factors are beyond Devon's control and are difficult to predict. In addition to volatility in general, Devon's oil, gas and NGL prices may vary considerably due to differences between regional markets, transportation availability and demand for different grades of oil, gas and NGLs. Substantially all of Devon's revenues are attributable to sales of these three commodities. Consequently, Devon's financial results and resources are highly influenced by price volatility.

Estimates for Devon's future production of oil, natural gas and NGLs are based on the assumption that market demand and prices for oil and gas will continue at levels that allow for profitable production of these products. There can be no assurance of such stability. Also, Devon's international production of oil, natural gas and NGLs is governed by payout agreements with the governments of the countries in which Devon operates. If the payout under these agreements is attained earlier than projected, Devon's net production and proved reserves in such areas could be reduced.

Estimates for Devon's future processing and transport of natural gas and NGLs are based on the assumption that market demand and prices for gas and NGLs will continue at levels that

allow for profitable processing and transport of these products. There can be no assurance of such stability.

The production, transportation, processing and marketing of oil, natural gas and NGLs are complex processes which are subject to disruption due to transportation and processing availability, mechanical failure, human error, meteorological events including, but not limited to, hurricanes, and numerous other factors. The following forward-looking statements were prepared assuming demand, curtailment, producibility and general market conditions for Devon's oil, natural gas and NGLs during 2002 will be substantially similar to those of 2001, unless otherwise noted. Given the general limitations expressed herein, Devon's forward-looking statements for 2002 are set forth below. Unless otherwise noted, all of the following dollar amounts are expressed in U.S. dollars. Those amounts related to Canadian operations have been converted to U.S. dollars using an exchange rate of $0.65 U.S. dollar to $1.00 Canadian dollar. The actual 2002 exchange rate may vary materially from this estimated rate. Such variations could have a material effect on the following Canadian estimates.

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

GEOGRAPHIC REPORTING AREAS FOR 2002 The following estimates of production, average price differentials and capital expenditures are provided separately for each of the following geographic areas:

- the United States;

- Canada; and

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

YEAR 2002 POTENTIAL OPERATING ITEMS

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

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

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

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

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

Devon has executed price swaps attributable to 8 MMBbls of domestic production at an average price of $23.85 per Bbl. Additionally, Devon has entered into price swaps attributable to Canadian production of 1.6 MMBbls at an average price of $20.33 per Bbl.

OIL PRICES - - FLOATING For oil production for which prices have not been fixed, Devon's average prices are expected to differ from the NYMEX price as set forth in the following table.

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

Devon has also entered into costless price collars that set a floor price and a ceiling price for 7.3 MMBbls of United States oil production that otherwise is subject to floating prices. The collars have a floor and ceiling price per Bbl of $23.00 and $28.19, respectively. The floor and ceiling prices are based on the NYMEX price. The NYMEX price is the monthly average of settled prices on each trading day for West Texas Intermediate Crude oil delivered at Cushing, Oklahoma. If the NYMEX price is outside of the ranges set by the floor and ceiling prices in the various collars, Devon and the counterparty to the collars will settle the difference. Any such settlements will either increase or decrease Devon's oil revenues for the period. Because Devon's oil volumes are often sold at prices that differ from the NYMEX price due to differing quality (i.e., sweet crude versus sour crude) and transportation costs from different geographic areas, the floor and ceiling prices of the various collars do not reflect actual limits of Devon's realized prices for the production volumes related to the collars.

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

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

GAS PRICES - - FIXED Through various price swaps and fixed-price physical delivery contracts, Devon has fixed the price it will receive on a portion of its natural gas production. The following tables include information on this fixed-price production. Where necessary, the prices have been adjusted for certain transportation costs that are netted against the prices recorded by Devon, and the prices have also been adjusted for the Btu content of the gas hedged.

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

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

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

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

Devon has entered into costless collars concerning its 2002 gas production. To simplify presentation, these collars have been aggregated in the following table according to similar floor prices. The floor and ceiling prices shown are weighted averages of the various collars in each aggregated group.

The prices shown in the following table have been adjusted to a NYMEX-based price, using Devon's estimates of 2002 differentials between NYMEX and the specific regional indices upon which the collars are based. The floor and ceiling prices related to the domestic collars are based on various regional first-of-the-month price indices as published monthly by Inside FERC. The floor and ceiling prices related to the Canadian collars are based on the AECO index as published by the Canadian Gas Price Reporter.

55

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

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

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

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

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

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

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

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

DEPRECIATION, DEPLETION AND AMORTIZATION ("DD&A") The 2002 oil and gas property DD&A rate will depend on various factors. Most notable among such factors are the amount of

proved reserves that will be added from drilling or acquisition efforts compared to the costs incurred for such efforts, and the revisions to Devon's year-end 2001 reserve estimates that, based on prior experience, are likely to be made during 2002.

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

GENERAL AND ADMINISTRATIVE EXPENSES ("G&A") Devon's G&A includes the costs of many different goods and services used in support of its business. These goods and services are subject to general price level increases or decreases. In addition, Devon's G&A varies with its level of activity and the related staffing needs as well as with the amount of professional services required during any given period. Should Devon's needs or the prices of the required goods and services differ significantly from current expectations, actual G&A could vary materially from the estimate. Given these limitations, consolidated G&A is expected to be between $174 million and $184 million.

INTEREST EXPENSE Future interest rates, debt outstanding and oil, natural gas and NGL prices have a significant effect on Devon's interest expense. Devon can only marginally influence the prices it will receive in 2002 from sales of oil, natural gas and NGLs and the resulting cash flow. The proceeds and the timing of the potential property sales in 2002 will also affect interest expense. Such proceeds could be used to retire either fixed-rate debt or variable-rate debt. At this time, the amount of proceeds and the timing of such property sales, as well as the application of the proceeds, are not possible to accurately predict. (See "Property Acquisitions and Divestitures.") These factors increase the margin of error inherent in estimating future interest expense. Other factors which affect interest expense, such as the amount and timing of capital expenditures, are within Devon's control.

Assuming no changes in fixed-rate debt balances during 2002 other than the assumption of $211 million of such debt from Mitchell, Devon's average balance of fixed rate debt during 2002 will be $5.7 billion. The interest expense in

2002 related to this fixed-rate debt will be approximately $407 million. This fixed-rate debt removes the uncertainty of future interest rates from some, but not all, of Devon's long-term debt. Devon's floating rate debt is discussed in the following paragraphs.

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

57

From time to time, Devon borrows under its $1 billion credit facilities. Borrowings under the U.S. facility, currently set at $725 million, may be borrowed at various rate options including LIBOR plus a margin with interest periods of up to six months. Borrowings under the Canadian facility, currently set at $275 million, may be made at various rate options including LIBOR plus a margin with interest periods up to six months, or Bankers Acceptances plus a margin with interest periods of 30 to 180 days. The current LIBOR margin ranges from 45.0 to 47.5 basis points and the current Bankers Acceptance margin is 45.0 basis points. The total borrowed under these facilities was $50 million at December 31, 2001, at an average interest rate of 4.8%.

From time to time, Devon also borrows under its commercial paper facility. Total borrowings under the $725 million U.S. facility and the commercial paper program cannot exceed $725 million. The total borrowed under the commercial paper program was $75 million at December 31, 2001, at an average interest rate of 3.5%. Debt outstanding under this program is generally borrowed for seven to 90 day periods, and may be borrowed up to 365 days, at prevailing commercial paper market rates.

Devon has fixed the interest rate on $133 million Canadian dollars and $50 million U.S. dollars of its floating rate debt through interest-rate swap agreements at average rates of 6.4% and 5.9%, respectively. The Canadian dollar interest-rate swap agreements mature at various dates through July 2007 and the U.S. dollar swap agreement matures in May 2003.

REDUCTION OF CARRYING VALUE OF OIL AND GAS PROPERTIES Devon follows the full cost method of accounting for its oil and gas properties. Under the full cost method, Devon's net book value of oil and gas properties, less related deferred income taxes (the "costs to be recovered"), may not exceed a calculated "full cost ceiling." The ceiling limitation is the discounted estimated after-tax future net revenues from oil and gas properties plus the lower of cost or fair value of unproved properties. The ceiling is imposed separately by country. In calculating future net revenues, current prices and costs are generally held constant indefinitely. The costs to be recovered are compared to the ceiling on a quarterly basis. If the costs to be recovered exceed the ceiling, the excess is written off as an expense. An expense recorded in one period may not be reversed in a subsequent period even though higher oil and gas prices may have increased the ceiling applicable to the subsequent period.

Because of the volatile nature of oil and gas prices, it is not possible to predict whether Devon will incur a full cost writedown in future periods. Because the ceiling calculation dictates that prices in effect as of the last day of the applicable quarter are held constant indefinitely, the resulting value is not indicative of the true fair value of the reserves. Oil and natural gas prices have historically been cyclical and, on any particular day at the end of a quarter, can be either substantially higher or lower than Devon's long-term price forecast that is a barometer for true fair value. Therefore, oil and gas property writedowns that result from applying the full cost ceiling limitation, and that are caused by fluctuations in price as opposed to reductions to the underlying quantities of reserves, should not be viewed as absolute indicators of a reduction of the ultimate value of the related reserves.

Devon recorded writedowns to its domestic and Canadian oil and gas properties as of December 31, 2001. The year-end 2001 prices used to calculate the ceiling were a NYMEX oil

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

EFFECTS OF CHANGES IN FOREIGN CURRENCY RATES In the October 2001 Anderson acquisition, Devon's subsidiary, Devon Canada, assumed $400 million of long-term debt which is denominated in U.S. dollars. This debt matures in 2011. Changes in the exchange rate between the U.S. dollar and the Canadian dollar from October 15, when Devon acquired Anderson, to the dates of repayment will increase or decrease the expected amount of Canadian dollars eventually required to repay the debt. Such changes in the Canadian dollar equivalent balance of the debt are required to be included in determining net earnings for the period in which the exchange rate changes. Because of the variability of the exchange rate, it is not possible to estimate the effect which will be recorded in 2002. However, for every $0.01 change in the exchange rate, Devon will record either revenue or expense of approximately $9 million Canadian dollars. The resulting revenue or expense in U.S. dollars will depend on the currency exchange rate in effect throughout the year.

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

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

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

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

PROPERTY ACQUISITIONS AND DIVESTITURES Though Devon has completed several major property acquisitions in recent years, these transactions are opportunity driven. Thus, Devon does not "budget," nor can it reasonably predict, the timing or size of such possible acquisitions, if any, other than the Mitchell acquisition closed on January 24, 2002.

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

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

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

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

YEAR 2002 POTENTIAL CAPITAL EXPENDITURES AND OTHER CASH USES

CAPITAL EXPENDITURES Though Devon has completed several major property acquisitions in recent years, these transactions are opportunity driven. Thus, Devon does not "budget", nor can it reasonably predict, the timing or size of such possible acquisitions, if any, other than the Mitchell acquisition.

Devon's capital expenditures budget is based on an expected range of future oil, natural gas and NGL prices as well as the expected costs of the capital additions. Should actual prices differ materially from Devon's expectations for its future production, some projects may be accelerated or deferred and, consequently, may increase or decrease total 2002 capital expenditures. In addition, if the actual costs of the budgeted items vary significantly from the anticipated amounts, actual capital expenditures could vary materially from Devon's estimates.

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

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

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

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

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

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

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

OTHER CASH USES Devon's management expects the policy of paying a quarterly common stock dividend to continue. With the current $0.05 per share quarterly dividend rate and 155 million shares of common stock outstanding after completion of the Mitchell acquisition, 2002 dividends are expected to approximate $31 million. Also, Devon has $150 million of 6.49% cumulative preferred stock upon which it will pay $10 million of dividends in 2002.

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

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

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

Also in June 2001, the FASB issued SFAS No. 143, Accounting for Asset Retirement Obligations. SFAS No. 143 requires liability recognition for retirement obligations associated with tangible long-lived assets, such as producing well sites, offshore production platforms, and natural gas processing plants. The obligations included within the scope of SFAS No. 143 are those for which a company faces a legal obligation for settlement. The initial measurement of the asset retirement obligation is to be fair value, defined as "the price that an entity would have to pay a willing third party of comparable credit standing to assume the liability in a current transaction other than in a forced or liquidation sale." Devon expects that it will use a valuation technique such as expected present value to estimate fair value.

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

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

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

In August 2001, the FASB issued SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets, which supersedes both SFAS No. 121, Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of and the accounting and reporting provisions of APB Opinion No. 30, Reporting the Results of Operations-Reporting the Effects of Disposal of a Segment of a Business, and Extraordinary,

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

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

ITEM 7A. 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 Devon views and manages its ongoing market risk exposures. All of Devon's market risk sensitive instruments were entered into for purposes other than trading.

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

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

Devon's total hedged positions as of January 31, 2002 are set forth in the following tables.

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

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

	GAS PRODUCTION			
	FIRST HALF OF 2002		SECOND HALF OF 2002	
	MCF/DAY	PRICE/MCF	MCF/DAY	PRICE/MCF
United States	211,936	$3.11	198,346	$3.19
Canada	40,673	$2.13	33,472	$2.12

	FIRST HALF OF 2003		SECOND HALF OF 2003	
	MCF/DAY	PRICE/MCF	MCF/DAY	PRICE/MCF
United States	89,726	$3.50	100,000	$3.32
Canada	5,000	$2.49	5,000	$2.03

	FIRST HALF OF 2004		SECOND HALF OF 2004	
	MCF/DAY	PRICE/MCF	MCF/DAY	PRICE/MCF
United States	--	$ --	--	$ --
Canada	5,000	$2.58	3,342	$2.03

COSTLESS PRICE COLLARS Devon has also entered into costless price collars that set a floor and ceiling price for a portion of its 2002 and 2003 oil and natural gas production. The following tables include information on these collars for each geographic area. The floor and ceiling prices related to domestic oil production are based on NYMEX. The NYMEX price is the monthly average of settled prices on each trading day for West Texas Intermediate Crude oil delivered at Cushing, Oklahoma. The gas prices shown in the following table have been adjusted to a NYMEX-based price, using Devon's estimates of differentials between NYMEX and the specific regional indices upon which the collars are based. The floor and ceiling prices related to the domestic collars are based on various regional first-of-the-month price indices as published

65

monthly by Inside FERC. The floor and ceiling prices related to the Canadian collars are based on the AECO index as published by the Canadian Gas Price Reporter.

If the applicable monthly price indices are outside of the ranges set by the floor and ceiling prices in the various collars, Devon and the counterparty to the collars will settle the difference. Any such settlements will either increase or decrease Devon's gas revenues for the period. Because Devon's gas volumes are often sold at prices that differ from the related regional indices, and due to differing Btu content of gas production, the floor and ceiling prices of the various collars do not reflect actual limits of Devon's realized prices for the production volumes related to the collars.

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

	OIL PRODUCTION				
	FIRST HALF OF 2002			SECOND HALF OF 2	
	BBLS/DAY	FLOOR PRICE PER BBL	CEILING PRICE PER BBL	BBLS/DAY	FLOOR PRICE PER BBL
United States	20,000	$23.00	$28.19	20,000	$23.00

	GAS PRODUCTION				
	FIRST HALF OF 2002			SECOND HALF OF 200	
	MMBTU/DAY	FLOOR PRICE PER MMBTU	CEILING PRICE PER MMBTU	MMBTU/DAY	FLOOR PRICE PER MMBTU
United States	450,000	$3.32	$6.27	320,000	$3.44
Canada	67,667	$3.15	$5.00	48,705	$3.17

	FIRST HALF OF 2003			SECOND HALF OF 200	
	MMBTU/DAY	FLOOR PRICE PER MMBTU	CEILING PRICE PER MMBTU	MMBTU/DAY	FLOOR PRICE PER MMBTU
United States	265,000	$3.18	$4.22	265,000	$3.18
Canada	80,000	$3.27	$4.07	80,000	$3.27

Devon uses a sensitivity analysis technique to evaluate the hypothetical effect that changes in the market value of oil and gas may have on the fair value of its commodity hedging instruments. At January 31, 2002, a 10% increase in the underlying commodities' prices would have reduced the fair value of Devon's commodity hedging instruments by $118 million.

66

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.

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

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

INTEREST RATE RISK At December 31, 2001, Devon had long-term debt outstanding of $6.6 billion. Of this amount, $5.4 billion, or 82%, bears interest at fixed rates averaging 7%. The remaining $1.2 billion of debt outstanding bears interest at floating rates which averaged 3%. In January 2002, Devon borrowed the remaining $2 billion on its $3 billion term loan credit facility to fund the Mitchell acquisition. The interest rate on the term loan credit facility is floating.

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

Devon assumed certain interest rate swaps as a result of the Anderson acquisition. Under these interest rate swaps, Devon has swapped a floating rate for a fixed rate. Under such swaps, Devon will record a fixed rate of 6.2% on $132 million of debt in 2002, 6.3% on $97 million of debt in 2003, 6.4% on $79 million of debt in 2004 through 2006 and 6.3% on $24 million of debt in 2007. The amount of gains or losses realized from such swaps are included as increases or decreases to interest expense.

Devon uses a sensitivity analysis technique to evaluate the hypothetical effect that changes in interest rates may have on the fair value of its interest rate swap instruments. At January 31, 2002, a 10% increase in the underlying interest rates would have decreased the fair value of Devon's interest rate swaps by $1 million.

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

FOREIGN CURRENCY RISK Devon's net assets, net earnings and cash flows from its Canadian subsidiaries are based on the U.S. dollar equivalent of such amounts measured in the Canadian dollar functional currency. Assets and liabilities of the Canadian subsidiaries are translated to U.S.

67

dollars using the applicable exchange rate as of the end of a reporting period. Revenues, expenses and cash flow are translated using the average exchange rate during the reporting period.

As a result of the Anderson acquisition, Devon's Canadian subsidiary, Devon Canada, assumed $400 million of fixed-rate long-term debt that is denominated in U.S. dollars. Changes in the currency conversion rate between the Canadian and U.S. dollars between the beginning and end of a reporting period increase or decrease the expected amount of Canadian dollars required to repay the notes. The amount of such increase or decrease is required to be included in determining net earnings for the period in which the exchange rate changes. A $0.03 decrease in the Canadian-to-U.S. dollar exchange rate would cause Devon to record a charge of approximately $20 million. The $400 million becomes due in March 2011. Until then, the gains or losses caused by the exchange rate fluctuations have no effect on cash flow.

Devon assumed certain foreign currency exchange rate swaps in the Anderson acquisition. These swaps require Devon to sell $30 million in 2002 and $12 million in 2003 at average Canadian-to-U.S. exchange rates of $0.680 and $0.676, and buy the same amount of dollars at the floating exchange rate. The amount of gains or losses realized from such swaps are included as increases or decreases to realized gas sales. At the December 31, 2001 exchange rate, these swaps would result in a decrease to gas sales during 2002 and 2003 of approximately $2 million and $1 million, respectively. A further $0.03 decrease in the Canadian-to-U.S. dollar exchange rate would result in an additional decrease to 2002 and 2003 gas sales of approximately $1 million in each year.

For purposes of the sensitivity analysis described above for changes in the Canadian dollar exchange rate, a change in the rate of $0.03 was used as opposed to a 10% change in the rate. During the last nine years, the Canadian-to-U.S. dollar exchange rate has fluctuated an average of approximately 4% per year, and no year's fluctuation was greater than 7%. The $0.03 change used in the above analysis represents an approximate 4% change in the year-end 2001 rate.

68

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS AND CONSOLIDATED

FINANCIAL STATEMENT SCHEDULES

All financial statement schedules are omitted as they are inapplicable or the required information has been included in the consolidated financial statements or notes thereto.

INDEPENDENT AUDITORS' REPORT

The Board of Directors and Stockholders
Devon Energy Corporation:

We have audited the accompanying consolidated balance sheets of Devon Energy Corporation and subsidiaries (the Company) as of December 31, 2001, 2000 and 1999, and the related consolidated statements of operations, stockholders' equity, and cash flows for each of the years then ended. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We did not audit the 1999 financial statements of Santa Fe Snyder Corporation, a wholly-owned subsidiary, which statements reflect total assets constituting 24% in 1999 of the related consolidated totals, and which statements reflect total revenues constituting 41% in 1999 of the related consolidated totals. The 1999 financial statements of Santa Fe Snyder Corporation were audited by other auditors whose report has been furnished to us, and our opinion, insofar as it relates to the amounts included for Santa Fe Snyder Corporation in 1999 is based solely on the report of the other auditors.

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

In our opinion, based on our audits and the report of the other auditors, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Devon Energy Corporation and subsidiaries as of December 31, 2001, 2000 and 1999, and the results of their operations and their cash flows for each of the years then ended, in conformity with accounting principles generally accepted in the United States of America.

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

KPMG LLP

Oklahoma City, Oklahoma
February 5, 2002

70

REPORT OF INDEPENDENT ACCOUNTANTS

To the Board of Directors of
Santa Fe Snyder Corporation:

In our opinion, the accompanying consolidated balance sheet and the related consolidated statements of operations, comprehensive income, shareholders' equity and of cash flows present fairly, in all material respects, the financial position of Santa Fe Snyder Corporation and its subsidiaries at December 31, 1999 and the results of their operations and their cash flows for the year ended December 31, 1999 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management; our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit of these statements in accordance with auditing standards generally accepted in the United States of America, which 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, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

As further described in Note 2, these consolidated financial statements have been retroactively restated to the full cost method of accounting for the Company's oil and gas properties in order to conform to the accounting policies of Devon Energy Corporation.

PricewaterhouseCoopers LLP

Houston, Texas
January 28, 2000, except for Note 2 and the second paragraph
above which are as of October 30, 2000

71

DEVON ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(IN MILLIONS, EXCEPT SHARE DATA)

	DECEMBE	
	2001	20
ASSETS		
Current assets:		
Cash and cash equivalents	$ 193	
Accounts receivable	537	
Inventories	41	
Deferred income taxes	--	
Fair value of financial instruments	195	
Income taxes receivable	68	
Investments and other current assets	47	
Total current assets	1,081	
Property and equipment, at cost, based on the full cost method of accounting for oil and gas properties ($1,939, $315 and $301 excluded from amortization in 2001, 2000 and 1999, respectively)	15,598	9,
Less accumulated depreciation, depletion and amortization	6,570	4,
	9,028	4,
Investment in ChevronTexaco Corporation common stock, at fair value	636	
Fair value of financial instruments	31	
Goodwill	2,206	
Other assets	202	
Total assets	$ 13,184	6,
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable:		
Trade	465	
Revenues and royalties due to others	170	
Income taxes payable	30	
Accrued interest payable	102	
Merger related expenses payable	7	
Fair value of financial instruments	15	
Deferred income taxes	57	
Accrued expenses	73	
Total current liabilities	919	
Other liabilities	179	
Debentures exchangeable into shares of ChevronTexaco Corporation common stock	649	
Other long-term debt	5,940	1,
Deferred revenue	51	
Fair value of financial instruments	45	
Deferred income taxes	2,142	
Stockholders' equity:		
Preferred stock of $1.00 par value ($100 liquidation value) Authorized 4,500,000 shares; issued 1,500,000 in 2001, 2000 and 1999	1	
Common stock of $.10 par value		

Authorized 400,000,000 shares; issued 126,132,000 in 2001, 128,638,000 in 2000 and 126,323,000 in 1999	13	
Additional paid-in capital	3,610	3,
Accumulated deficit	(147)	(
Accumulated other comprehensive loss	(28)	
Unamortized restricted stock awards	--	
Treasury stock, at cost: 3,754,000 shares in 2001 and 330,000 shares in 1999	(190)	
Total stockholders' equity	3,259	3,
Commitments and contingencies (Notes 12 and 13)		
Total liabilities and stockholders' equity	$ 13,184	6,

See accompanying notes to consolidated financial statements.

72

DEVON ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(IN MILLIONS, EXCEPT PER SHARE AMOUNTS)

	YEAR END
	2001
REVENUES	
Oil sales	$ 958
Gas sales	1,890
Natural gas liquids sales	132
Other	95
Total revenues	3,075
COSTS AND EXPENSES	
Lease operating expenses	531
Transportation costs	83
Production taxes	117
Depreciation, depletion and amortization of property and equipment	876
Amortization of goodwill	34
General and administrative expenses	111
Expenses related to mergers	1
Interest expense	220
Effects of changes in foreign currency exchange rates	13
Distributions on preferred securities of subsidiary trust	--
Change in fair value of financial instruments	2
Reduction of carrying value of oil and gas properties	1,003
Total costs and expenses	2,991
Earnings (loss) before income taxes, extraordinary item and cumulative effect of change in accounting principle	84

INCOME TAX EXPENSE (BENEFIT)	
Current	71
Deferred	(41)
Total income tax expense (benefit)	30
Earnings (loss) before extraordinary item and cumulative effect of change in accounting principle	54
Extraordinary loss	--
Earnings (loss) before cumulative effect of change in accounting principle	54
Cumulative effect of change in accounting principle	49
Net earnings (loss)	103
Preferred stock dividends	10
Net earnings (loss) applicable to common shareholders	$ 93
Net earnings (loss) per average common share outstanding:	
Before extraordinary loss and cumulative effect of change in accounting principle:	
Basic	$ 0.34
Diluted	$ 0.34
Before cumulative effect of change in accounting principle:	
Basic	$ 0.34
Diluted	$ 0.34
Applicable to common shareholders:	
Basic	$ 0.73
Diluted	$ 0.72
Weighted average common shares outstanding:	
Basic	128
Diluted	130

See accompanying notes to consolidated financial statements.

DEVON ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
(IN MILLIONS)

ADDITIONAL ACCU

	PREFERRED STOCK	COMMON STOCK	PAID-IN CAPITAL	LATE DEFI
Balance as of December 31, 1998	$ --	7	1,524	(73
Comprehensive loss:				
Net loss	--	--	--	(15
Other comprehensive earnings (loss), net of tax:				
Foreign currency translation adjustments	--	--	--	-
Unrealized loss on marketable securities	--	--	--	-
Other comprehensive loss	--	--	--	-
Comprehensive loss				
Stock issued	1	6	1,967	(
Stock repurchased	--	--	--	-
Tax benefit related to employee stock options	--	--	1	-
Dividends on common stock	--	--	--	(1
Dividends on preferred stock	--	--	--	(
Amortization of restricted stock awards	--	--	--	-
Balance as of December 31, 1999	1	13	3,492	(90
Comprehensive loss:				
Net earnings	--	--	--	73
Other comprehensive earnings (loss), net of tax:				
Foreign currency translation adjustments	--	--	--	-
Minimum pension liability adjustment	--	--	--	-
Unrealized loss on marketable securities	--	--	--	-
Other comprehensive loss	--	--	--	-
Comprehensive earnings				
Stock issued	--	--	69	(
Stock repurchased	--	--	--	-
Tax benefit related to employee stock options	--	--	3	-
Dividends on common stock	--	--	--	(2
Dividends on preferred stock	--	--	--	(1
Grant of restricted stock awards	--	--	--	-
Amortization of restricted stock awards	--	--	--	-
Balance as of December 31, 2000	1	13	3,564	(21
Comprehensive earnings:				
Net earnings	--	--	--	10
Other comprehensive earnings (loss), net of tax:				
Foreign currency translation adjustments	--	--	--	-
Cumulative effect of change in				

Accounting principle	--	--	--	-
Reclassification adjustment for Derivative (gains) losses reclassified Into oil and gas sales	--	--	--	-
Change in fair value of financial instruments	--	--	--	-
Minimum pension liability adjustment	--	--	--	-
Unrealized gain on marketable securities	--	--	--	-
Other comprehensive earnings	--	--	--	-
Comprehensive earnings				
Stock issued	--	--	48	-
Stock repurchased	--	--	(14)	-
Tax benefit related to employee stock options	--	--	12	-
Dividends on common stock	--	--	--	(2
Dividends on preferred stock	--	--	--	(1
Amortization of restricted stock awards	--	--	--	-
Balance as of December 31, 2001	$ 1	13	3,610	(14

	TREASURY STOCK	TOTAL STOCK-HOLDERS' EQUITY
Balance as of December 31, 1998	(7)	750
Comprehensive loss:		
Net loss	--	(154)
Other comprehensive earnings (loss), net of tax:		
Foreign currency translation adjustments	--	7
Unrealized loss on marketable securities	--	(36)
Other comprehensive loss	--	(29)
Comprehensive loss		(183)
Stock issued	8	1,981
Stock repurchased	(12)	(12)
Tax benefit related to employee stock options	--	1
Dividends on common stock	--	(13)
Dividends on preferred stock	--	(4)
Amortization of restricted stock awards	--	1

Balance as of December 31, 1999	(11)	2,521
Comprehensive loss:		
Net earnings	--	730
Other comprehensive earnings (loss), net of tax:		
Foreign currency translation adjustments	--	(10)
Minimum pension liability adjustment	--	1
Unrealized loss on marketable securities	--	(11)
Other comprehensive loss	--	(20)
		710
Comprehensive earnings		
Stock issued	21	86
Stock repurchased	(10)	(10)
Tax benefit related to employee stock options	--	3
Dividends on common stock	--	(22)
Dividends on preferred stock	--	(10)
Grant of restricted stock awards	--	(5)
Amortization of restricted stock awards	--	4
Balance as of December 31, 2000	--	3,277
Comprehensive earnings:		
Net earnings	--	103
Other comprehensive earnings (loss), net of tax:		
Foreign currency translation adjustments	--	(107)
Cumulative effect of change in Accounting principle	--	(37)
Reclassification adjustment for Derivative (gains) losses reclassified Into oil and gas sales	--	(20)
Change in fair value of financial instruments	--	216
Minimum pension liability adjustment	--	(17)
Unrealized gain on marketable securities	--	22
Other comprehensive earnings	--	57
		160
Comprehensive earnings		
Stock issued	--	48
Stock repurchased	(190)	(204)
Tax benefit related to employee stock options	--	12
Dividends on common stock	--	(25)
Dividends on preferred stock	--	(10)
Amortization of restricted stock awards	--	1
Balance as of December 31, 2001	(190)	3,259

See accompanying notes to consolidated financial statements.

DEVON ENERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(IN MILLIONS)

	YEAR ENDED D	
	2001	200
CASH FLOWS FROM OPERATING ACTIVITIES		
Net earnings (loss)	$ 103	
Adjustments to reconcile net earnings (loss) to net cash provided by operating activities:		
Depreciation, depletion and amortization of property and equipment	876	
Amortization of goodwill	34	
Accretion (amortization) of discounts (premiums) on long-term debt, net	26	
Effects of changes in foreign currency exchange rates	13	
Change in fair value of financial instruments	2	
Reduction of carrying value of oil and gas properties	1,003	
Loss (gain) on sale of assets	2	
Deferred income tax expense (benefit)	(41)	
Cumulative effect of change in accounting principle	(49)	
Other	(3)	
Changes in assets and liabilities, net of effects of acquisitions of businesses:		
Decrease (increase) in:		
Accounts receivable	191	(
Inventories	15	
Income taxes receivable	(68)	
Investments and other current assets	2	
(Decrease) increase in:		
Accounts payable	29	
Income taxes payable	(117)	
Accrued interest and expenses	(46)	
Deferred revenue	(63)	
Long-term other liabilities	(23)	
Net cash provided by operating activities	1,886	1,
CASH FLOWS FROM INVESTING ACTIVITIES		
Proceeds from sale of property and equipment	41	
Proceeds from sale of investments	--	
Capital expenditures, including acquisitions of businesses	(5,326)	(1,
(Increase) decrease in other assets	--	
Net cash used in investing activities	(5,285)	(1,
CASH FLOWS FROM FINANCING ACTIVITIES		

Proceeds from borrowings of long-term debt, net of issuance costs	6,199	2,
Principal payments on long-term debt	(2,638)	(2,
Issuance of common stock, net of issuance costs	48	
Repurchase of common stock	(204)	
Issuance of treasury stock	--	
Dividends paid on common stock	(25)	
Dividends paid on preferred stock	(10)	
(Decrease) increase in long-term other liabilities	--	
Net cash provided by (used in) financing activities	3,370	(
Effect of exchange rate changes on cash	(6)	
Net (decrease) increase in cash and cash equivalents	(35)	
Cash and cash equivalents at beginning of year	228	
Cash and cash equivalents at end of year	$ 193	$

See accompanying notes to consolidated financial statements.

DEVON ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
DECEMBER 31, 2001, 2000 AND 1999

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.

Use of Estimates in the Preparation of Financial Statements

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

Property and Equipment

Devon follows the full cost method of accounting for its oil and gas properties. Accordingly, all costs incidental to the acquisition, exploration and development of oil and gas properties, including costs of undeveloped leasehold, dry holes and leasehold equipment, are capitalized. Internal costs incurred that are directly identified with acquisition, exploration and development activities undertaken by Devon for its own account, and which are not related to production, general corporate overhead or similar activities are also capitalized. For the years 2001, 2000 and 1999, such internal costs capitalized totaled $77 million, $62 million and $29 million, respectively.

Unproved properties are excluded from amortized capitalized costs until it is determined whether or not proved reserves can be assigned to such properties. Devon assesses its unproved properties for impairment at least annually.

Net capitalized costs are limited to the estimated future net revenues, discounted at 10% per annum, from proved oil, natural gas and natural gas liquids reserves plus the lower of cost or fair value of unproved properties. Such limitations are imposed separately on a country-by-country basis and are tested quarterly. Capitalized costs are depleted by an equivalent unit-of-production method, converting gas to oil at the ratio of six thousand cubic feet of natural gas to one barrel of oil. Depletion is calculated using the capitalized costs plus the estimated future expenditures (based on current costs) to be incurred in developing proved reserves, and the estimated dismantlement and abandonment costs, net of estimated salvage values. No gain or loss is recognized upon disposal of oil and gas properties unless such disposal significantly alters the relationship between capitalized costs and proved reserves. All costs related to production activities, including workover costs incurred solely to maintain or increase levels of production from an existing completion interval, are charged to expense as incurred.

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

Marketable Securities and Other Investments

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

Goodwill

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

funds. The assessment of the recoverability of goodwill will be impacted if estimated future operating cash flows are not achieved.

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

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

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

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

Revenue Recognition and Gas Balancing

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

monitored over the lives of the wells' production capability. If an imbalance exists at the time the wells' reserves are depleted, cash settlements are made among the joint interest owners under a variety of arrangements.

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

Hedging Activities

Devon has periodically entered into oil and gas financial instruments and foreign exchange rate swaps to manage its exposure to oil and gas price volatility. The foreign exchange rate swaps mitigate the effect of volatility in the Canadian-to-U.S. dollar exchange rate on Canadian oil and gas revenues that are predominantly based on U.S. dollar prices. The hedging instruments are usually placed with counterparties that Devon believes are minimal credit risks. It is Devon's policy to only enter into derivative contracts with investment grade rated counterparties deemed by management to be competent and competitive market makers. The oil and gas reference prices upon which the price hedging instruments are based reflect various market indices that have a high degree of historical correlation with actual prices received by Devon.

As of January 1, 2001, Devon adopted the provisions of SFAS No. 133, Accounting for Derivative Instruments and Certain Hedging Activities and SFAS No. 138, Accounting for Certain Derivative Instruments and Certain Hedging Activities, an Amendment of SFAS No. 133. SFAS Nos. 133 and 138 require that all derivative instruments be recorded on the balance sheet at their respective fair values. In accordance with the transition provisions of SFAS No. 133, Devon recorded a net-of-tax cumulative-effect-type adjustment of $37 million loss in accumulated other comprehensive loss to recognize the fair value of all derivatives that were designated as cash-flow hedging instruments. Additionally, Devon recorded a net-of-tax cumulative-effect-type adjustment to net earnings of $49 million gain ($0.38 per basic share and $0.37 per diluted share) related to the fair value of derivative instruments that did not qualify as hedges. This gain related principally to the option embedded in Devon's debentures that are exchangeable into shares of ChevronTexaco Corporation common stock.

All derivatives are recognized on the balance sheet at their fair value. The majority of Devon's derivatives that qualify for hedge accounting treatment are either "cash flow" hedges or "foreign currency cash flow" hedges (collectively, "cash flow hedges"). Devon designates its cash flow hedge derivatives as such on the date the derivative contract is entered into or the date of a business combination which includes cash flow hedges. Devon formally documents all relationships between hedging instruments and hedged items, as well as its risk-management objective and strategy for undertaking various hedge transactions. Devon also assesses, both at the hedge's inception and on an ongoing basis, whether the derivatives that are used in hedging transactions are highly effective in offsetting changes in cash flows of hedged items.

During 2001, there were no gains or losses reclassified into earnings as a result of the discontinuance of hedge accounting treatment for any of Devon's derivatives.

By using derivative instruments to hedge exposures to changes in commodity prices and exchange rates, Devon exposes itself to credit risk and market risk. Credit risk is the failure of the counterparty to perform under the terms of the derivative contract. To mitigate this risk, the hedging instruments are usually placed with counterparties that Devon believes are minimal credit risks.

Market risk is the adverse effect on the value of a derivative instrument that results from a change in interest rates, commodity prices, or currency exchange rates. The market risk associated with commodity price and foreign exchange contracts is managed by establishing and monitoring parameters that limit the types and degree of market risk that may be undertaken.

Devon does not hold or issue derivative instruments for trading purposes. The majority of Devon's commodity price swaps and costless price collars, interest rate swaps, and foreign exchange rate swaps in place at January 1, 2001 through December 31, 2001 have been designated as cash flow hedges. Changes in the fair value of these derivatives are reported on the balance sheet in "Accumulated other comprehensive loss" ("AOCL"). These amounts are reclassified to oil and gas sales or interest expense when the forecasted transaction takes place.

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

During the third quarter of 2001, Devon also entered into interest rate locks to reduce exposure to the variability in market interest rates, specifically U.S. Treasury rates, in anticipation of the sale of the debt securities discussed in Note 7. These derivative instruments were designated as cash flow hedges. A $28 million loss was incurred on these interest rate locks. This loss will be amortized into interest expense using the effective interest method over the life of the debt securities.

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

As of December 31, 2001, $180 million of net deferred gains on derivative instruments accumulated in AOCL are expected to be reclassified to earnings during the next 12 months. Transactions and events expected to occur over the next 12 months that will necessitate reclassifying

these derivatives' gains to earnings are primarily the production and sale of oil and gas which includes the production hedged under the various derivative instruments. The maximum term over which Devon is hedging exposures to the variability of cash flows for commodity price risk is 34 months.

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

Stock Options

Devon applies the intrinsic value-based method of accounting prescribed by Accounting Principles Board Opinion No. 25, Accounting for Stock Issued to Employees, and related interpretations, in accounting for its fixed plan stock options. As such, compensation expense would be recorded on the date of grant only if the current market price of the underlying stock exceeded the exercise price. SFAS No. 123, Accounting for Stock-Based Compensation, established accounting and disclosure requirements using a fair value-based method of accounting for stock-based employee compensation plans. As allowed by SFAS No. 123, Devon has elected to continue to apply the intrinsic value-based method of accounting described above, and has adopted the disclosure requirements of SFAS No. 123 which are included in Note 10.

Major Purchasers

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

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

Income Taxes

Devon accounts for income taxes using the asset and liability method, whereby deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of assets and liabilities and their respective tax bases, as well as the future tax consequences attributable to the future utilization of existing tax net operating loss and other types of carryforwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences and carryforwards are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date. U.S. deferred income taxes have not been provided on Canadian earnings which are being permanently reinvested.

General and Administrative Expenses

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

Net Earnings Per Common Share

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

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

	NET EARNINGS APPLICABLE TO COMMON STOCKHOLDERS	WEIGHTED AVERAGE COMMON SHARES OUTSTANDING
	(IN MILLIONS)	
YEAR ENDED DECEMBER 31, 2001:		
Basic earnings per share	$ 93	128
Dilutive effect of potential common shares issuable upon the exercise of outstanding stock options	--	2

Diluted earnings per share	$ 93	130
	====	===
YEAR ENDED DECEMBER 31, 2000:		
Basic earnings per share	$720	127
Dilutive effect of:		
Potential common shares issuable upon conversion of senior convertible debentures (the increase in net earnings is net of income tax expense of $3)	5	3
Potential common shares issuable upon the exercise of outstanding stock options	--	2
	----	---
Diluted earnings per share	$725	132
	====	===

The senior convertible debentures were not included in the 2001 dilution calculation because the inclusion was anti-dilutive.

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

Comprehensive Earnings or Loss

Devon's comprehensive earnings or loss information is included in the accompanying consolidated statements of stockholders' equity. A summary of accumulated other comprehensive

earnings or loss as of December 31, 2001, 2000 and 1999, and changes during each of the years then ended, is presented in the following table.

	FOREIGN CURRENCY TRANSLATION	CHANGE IN FAIR VALUE OF FINANCIAL INSTRU-	MINIMUM PENSION LIABILITY ADJUST-	UN GAIN MARK

	ADJUSTMENTS	MENTS	MENTS	SEC
			(IN MILLIONS)	
Balance as of December 31, 1998	$ (35)	$ --	$ (1)	
1999 activity	7	--	--	
Deferred taxes	--	--	--	
1999 activity, net of deferred taxes	7	--	--	
Balance as of December 31, 1999	(28)	--	(1)	
2000 activity	(10)	--	1	
Deferred taxes	--	--	--	
2000 activity, net of deferred taxes	(10)	--	1	
Balance as of December 31, 2000	(38)	--	--	
2001 activity	(107)	243	(28)	
Deferred taxes	--	(84)	11	
2001 activity, net of deferred taxes	(107)	159	(17)	
Balance as of December 31, 2001	$(145)	$ 159	$(17)	

Foreign Currency Translation Adjustments

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

Dividends

Dividends on Devon's common stock were paid in 2001, 2000 and 1999 at a per share rate of $0.05 per quarter. As adjusted for the pooling-of-interests method of accounting followed for the Santa Fe Snyder merger, annual dividends per share for 2001, 2000 and 1999 were $0.20, $0.17 and $0.14, respectively.

Statements of Cash Flows

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

Commitments and Contingencies

Liabilities for loss contingencies arising from claims, assessments, litigation or other sources are recorded when it is probable that a liability has been incurred and the amount can be reasonably estimated.

Environmental expenditures are expensed or capitalized in accordance with accounting principles generally accepted in the United States of America. Liabilities for these expenditures are recorded when it is probable that obligations have been incurred and the amounts can be reasonably estimated. Reference is made to Note 13 for a discussion of amounts recorded for these liabilities.

Reclassification

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

2. BUSINESS COMBINATIONS AND PRO FORMA INFORMATION

Mitchell Energy & Development Corp. Merger

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

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

Anderson Exploration Ltd. Acquisition

On October 15, 2001, Devon accepted all of the Anderson common shares tendered by Anderson stockholders in the tender offer, which represented approximately 97% of the outstanding Anderson common shares. On October 17, 2001, Devon completed its acquisition of Anderson by a compulsory acquisition under the Canada Business Corporations Act of the remaining 3% of Anderson common shares. The cost to Devon of acquiring Anderson's outstanding common shares and paying for the intrinsic value of Anderson's outstanding options and appreciation rights was approximately $3.5 billion, which was funded from the sale of $3.0 billion of debt securities and borrowings under the $3.0 billion senior unsecured term loan credit facility (see Note 7).

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

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

	(IN MILLIONS, EXCEPT SHARE PRICE)
Calculation and preliminary allocation of purchase price:	
Number of Anderson common shares outstanding	132
Acquisition price per share	$25.68
Cash paid to Anderson stockholders	$3,386
Cash paid to settle Anderson employees' stock options and appreciation rights	92
	3,478
Plus estimated acquisition costs incurred	35
Total purchase price	3,513
Plus fair value of liabilities assumed by Devon:	
Current liabilities	249
Long-term debt	1,017
Other long-term liabilities	7
Fair value of financial instruments	30
Deferred income taxes	1,427
Total purchase price plus liabilities assumed	$6,243
Fair value of assets acquired by Devon:	
Current assets	214
Proved oil and gas properties	2,605
Unproved oil and gas properties	1,432
Other property and equipment	21
Goodwill (none deductible for income tax purposes)	1,971
Total fair value of assets acquired	$6,243

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

Santa Fe Snyder Merger

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

86

DEVON ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
DECEMBER 31, 2001, 2000 AND 1999

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

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

PennzEnergy Merger

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

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

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

Snyder Merger

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

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

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

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

3. SAN JUAN BASIN TRANSACTION

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

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

4. SUPPLEMENTAL CASH FLOW INFORMATION

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

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

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

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

5. ACCOUNTS RECEIVABLE

The components of accounts receivable included the following:

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

6. PROPERTY AND EQUIPMENT

Property and equipment included the following:

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

Property and equipment, net of accumulated depreciation, depletion and amortization	$ 9,028	4,910	4,424

The costs not subject to amortization relate to unproved properties, none of which are individually significant. Subject to industry conditions, evaluation of these properties is expected to be completed within five years.

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

	YEAR ENDED DECEMBER 31,		
	2001	2000	1999
	(IN MILLIONS)		
Depreciation, depletion and amortization of oil and gas properties	$838	663	390
Depreciation and amortization of other property and equipment	30	23	14
Amortization of other assets	8	7	2
Total	$876	693	406

DEVON ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
DECEMBER 31, 2001, 2000 AND 1999

7. LONG-TERM DEBT AND RELATED EXPENSES

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

	DECEMBER 3	
	2001	2000
	(IN MILLIO	
Borrowings under credit facilities with banks	$ 50	147
Commercial paper borrowings	75	--
$3 billion term loan credit facility	1,046	--
Debentures exchangeable into shares of ChevronTexaco Corporation common stock:		
4.90% due August 15, 2008	444	444
4.95% due August 15, 2008	316	316
Discount on exchangeable debentures	(111)	--
Zero coupon convertible senior debentures Exchangeable into shares of Devon Energy Corp.		

common stock, 3.875% due June 27, 2020	374	360
Other debentures:		
10.25% due November 1, 2005	236	250
10.125% due November 15, 2009	177	200
7.875% due September 30, 2031	1,250	--
Net premium on debentures	6	33
Senior notes:		
8.05% due June 15, 2004	125	125
7.25% due July 18, 2005	110	--
6.76% due July 19, 2005	--	--
7.42% due October 1, 2005	23	--
7.57% due October 4, 2005	31	--
6.55% due August 2, 2006	126	--
8.75% due June 15, 2007	175	175
6.79% due March 2, 2009	--	--
6.75% due March 15, 2011	400	--
6.875% due September 30, 2011	1,750	--
Net discount on notes	(14)	(1)
	6,589	2,049
Less amount classified as current	--	--
Long-term debt	$ 6,589	2,049

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

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

91

DEVON ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
DECEMBER 31, 2001, 2000 AND 1999

Credit Facilities With Banks

On August 13, 2001, Devon renewed its unsecured long-term credit facilities aggregating $1 billion (the "Credit Facilities"). The Credit Facilities include a U.S. facility of $725 million (the "U.S. Facility") and a Canadian facility of $275 million (the "Canadian Facility").

The $725 million U.S. Facility consists of a Tranche A facility of $200 million and a Tranche B facility of $525 million. The Tranche B facility can be increased to as high as $625 million and reduced to as low as $425 million by reallocating the amount available between the Tranche B facility and the Canadian Facility. The Tranche A facility matures on October 15, 2004. Devon may borrow funds under the Tranche B facility until August 12, 2002 (the "Tranche B Revolving Period"). Devon may request that the Tranche B Revolving Period be extended an additional 364 days by notifying the agent bank of such request between 30 and 60 days prior to the end of the Tranche B Revolving Period. Debt borrowed under the Tranche B facility matures two years and one day following the end of the Tranche B Revolving Period.

Devon may borrow funds under the $275 million Canadian Facility until August 12, 2002 (the "Canadian Facility Revolving Period"). As disclosed in the prior paragraph, the Canadian Facility can be increased to as high as $375 million and reduced to as low as $175 million by reallocating the amount available between the Tranche B facility and the Canadian Facility. Devon may request that the Canadian Facility Revolving Period be extended an additional 364 days by notifying the agent bank of such request between 45 and 90 days prior to the end of the Canadian Facility Revolving Period. Debt outstanding as of the end of the Canadian Facility Revolving Period is payable in semi-annual installments of 2.5% each for the following five years, with the final installment due five years and one day following the end of the Canadian Facility Revolving Period.

Amounts borrowed under the Credit Facilities bear interest at various fixed rate options that Devon may elect for periods up to six months. Such rates are generally less than the prime rate, and are tied to margins determined by Devon's corporate credit ratings. Devon may also elect to borrow at the prime rate. The Credit Facilities provide for an annual facility fee of $0.9 million that is payable quarterly. The weighted average interest rate on the $50 million and $147 million outstanding under the Credit Facilities at December 31, 2001 and 2000, was 4.8% and 6.1%, respectively. The average interest rate on bank debt outstanding under the previous facilities at December 31, 1999 was 6.8%.

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

92

DEVON ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
DECEMBER 31, 2001, 2000 AND 1999

Commercial Paper

On August 29, 2000, Devon entered into a commercial paper program. Devon may borrow up to $725 million under the commercial paper program. Total borrowings under the U.S. Facility and the commercial paper program may not exceed $725 million. The commercial paper borrowings may have terms of up to 365 days and bear interest at rates agreed to at the time of the borrowing. The interest rate is based on a standard index such as the Federal Funds Rate, London Interbank Offered Rate (LIBOR), or the money market rate as found on the commercial paper market. As of December 31, 2001, Devon had $75 million of borrowings under its commercial paper program at an average rate of 3.5%. Because Devon had the intent and ability to refinance the balance due with borrowings under its U.S. Facility, the $75 million outstanding under the commercial paper program was classified as long-term debt on the December 31, 2001 consolidated balance sheet.

$3 Billion Term Loan Credit Facility

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

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

Prior to December 31, 2001, Devon used proceeds of $1 billion from borrowings on this facility to partially fund the Anderson acquisition. The remaining $2 billion of availability was utilized upon the closing of the Mitchell acquisition on January 24, 2002.

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

	(In Millions)
2002	$ --
2003	--
2004	232
2005	1,200
2006	1,600
Total	$ 3,032

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

This credit facility contains certain covenants and restrictions, including a maximum allowed debt-to-capitalization ratio as defined in the credit facility. At December 31, 2001, Devon was in compliance with such covenants and restrictions.

Exchangeable Debentures

The exchangeable debentures consist of $444 million of 4.90% debentures and $316 million of 4.95% debentures. The exchangeable debentures were issued on

August 3, 1998 and mature August 15, 2008. The exchangeable debentures are callable beginning August 15, 2000, initially at 104.0% of principal and at prices declining to 100.5% of principal on or after August 15, 2007. The exchangeable debentures are exchangeable at the option of the holders at any time prior to maturity, unless previously redeemed, for shares of ChevronTexaco Corporation common stock. In lieu of delivering ChevronTexaco Corporation common stock, Devon may, at its option, pay to any holder an amount of cash equal to the market value of the ChevronTexaco Corporation common stock to satisfy the exchange request. However, at maturity, the holders will receive an amount at least equal to the face value of the debt outstanding. Such amount will either be in cash or in a combination of cash and ChevronTexaco Corporation common stock.

As of December 31, 2001, Devon beneficially owned approximately seven million shares of ChevronTexaco Corporation common stock. These shares have been deposited with an exchange agent for possible exchange for the exchangeable debentures. Each $1,000 principal amount of the exchangeable debentures is exchangeable into 9.3283 shares of ChevronTexaco Corporation common stock, an exchange rate equivalent to $107-7/32 per share of ChevronTexaco stock.

The exchangeable debentures were assumed as part of the PennzEnergy merger. The fair values of the exchangeable debentures were determined as of August 17, 1999, based on market quotations. The fair value approximated the face value of the exchangeable debentures. As a result, no premium or discount was recorded on these exchangeable debentures. However, pursuant to the adoption of SFAS No. 133 effective January 1, 2001, these debentures were

revalued as of August 17, 1999. Under SFAS No. 133, the total fair value of the debentures was allocated between the interest-bearing debt and the option to exchange ChevronTexaco Corporation common stock that is embedded in the debentures. Accordingly, the debt portion of the debentures was reduced by $140 million as of August 17, 1999. This discount is being accreted using the effective interest method, and has raised the effective interest rate on the debentures to 7.76% in 2001 compared to 4.92% prior to 2001.

Zero Coupon Convertible Debentures

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

Debt Securities

On October 3, 2001, Devon, through Devon Financing, sold $1.75 billion of 6.875% notes due September 30, 2011 and $1.25 billion of 7.875% debentures due September 30, 2031. The debt securities are unsecured and unsubordinated obligations of Devon Financing. Devon has fully and unconditionally guaranteed on an unsecured and unsubordinated basis the obligations of Devon Financing under the debt securities. The proceeds from the issuance of these debt securities were used to fund a portion of the Anderson acquisition.

The $3 billion of debt securities were structured in a manner that results in an expected weighted average after-tax borrowing rate of approximately 1.76%.

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

Other Debentures

The 10.25% and 10.125% debentures were assumed as part of the PennzEnergy merger. The fair values of the respective debentures were determined using August 17, 1999, market interest rates. As a result, premiums were recorded on these debentures which lowered their effective interest rates to 8.3% and 8.9% on the $236 million of 10.25% debentures and $177 million of 10.125% debentures, respectively. The premiums are being amortized using the effective interest method.

During October 2001, Devon repurchased $14 million and $23 million of its 10.25% debentures and 10.125% debentures, respectively. Devon recorded a loss on the early retirement of debt of $5 million related to this repurchase.

Senior Notes

In connection with the Anderson acquisition, Devon assumed $702 million of senior notes. The table below summarizes the debt assumed, the fair value of the debt at October 15, 2001, and the effective interest rate of the debt assumed after determining the fair values of the respective notes using October 15, 2001, market interest rates. The premiums and discounts are being amortized or accreted using the effective interest method. All of the notes are general unsecured obligations of Devon.

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

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

In connection with the Snyder merger, Devon assumed Snyder's $175 million of 8.75% notes due in 2007. The notes are redeemable by Devon on or after June 15, 2002, initially at 104.375% of principal and at prices declining to 100% of principal on or after June 15, 2005. The notes are general unsecured obligations of Devon. In June 1999, Devon issued $125 million of 8.05% notes due 2004. The notes were issued for 98.758% of face value and Devon received total proceeds of $122 million after deducting related costs and expenses of $2 million. The notes, which mature June 15, 2004, are redeemable, upon not less than thirty nor more than sixty days notice, as a whole or in part, at the option of Devon at a redemption price equal to the sum of (i) 100% of the principal amount thereof, (ii) the applicable make-whole premium as determined by an independent investment banker and (iii) accrued and unpaid interest. The notes are general unsecured obligations of Devon. The indentures for these notes include covenants that restrict the ability of Devon SFS Operating, Inc., a wholly-owned subsidiary of Devon, to take certain actions, including the ability to incur additional indebtedness and to pay dividends or repurchase capital stock.

Interest Expense

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

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

Effects of Changes in Foreign Currency Exchange Rates

The 6.75% fixed-rate senior notes referred to in the first table of this note are payable by Devon Canada, a wholly-owned subsidiary of Devon. However, the notes are denominated in U.S. dollars. Until their retirement in mid-January 2000, the 6.76% and 6.79% fixed-rate senior notes payable by Devon Canada were also denominated in U.S. dollars. Changes in the exchange rate between the U.S. dollar and the Canadian dollar from the dates the notes were issued to the dates of repayment increase or decrease the expected amount of

Canadian dollars eventually required to repay the notes. Such changes in the Canadian dollar equivalent of the debt are required to be included in determining net earnings for the period in which the exchange rate changed. The rate of conversion of Canadian dollars to U.S. dollars declined in 2001 and 2000 and increased in 1999. Therefore, $11 million and $3 million of increased expense was recorded in 2001 and 2000, respectively, and $13 million of reduced expense was recorded in 1999.

8. INCOME TAXES

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

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

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

The earnings (loss) before income taxes and the components of income tax expense (benefit) for the years 2001, 2000 and 1999 were as follows:

	YEAR ENDED DECEMBER 31,		
	2001	2000	1999
	(IN MILLIONS)		
Earnings (loss) before income taxes:			
U.S	$ 458	872	(313)
Canada	(357)	156	58
International	(17)	114	56
Total	$ 84	1,142	(199)
Current income tax expense:			
U.S. federal	$ 23	107	12
Various states	6	6	3
Canada	8	2	3
Other	34	16	5
Total current tax expense	71	131	23

Deferred income tax expense (benefit):			
U.S. federal	124	152	(119)
Various states	(32)	33	--
Canada	(145)	67	27
Other	12	29	20
Total deferred tax expense (benefit)	(41)	281	(72)
Total income tax expense (benefit)	$ 30	412	(49)

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

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

98

DEVON ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
DECEMBER 31, 2001, 2000 AND 1999

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

	DECEMBER 31,		
	2001	2000	1999
		(IN MILLIONS)	
Deferred tax assets:			
Net operating loss carryforwards	$ 39	123	207
Minimum tax credit carryforwards	118	85	88
Production payments	--	--	21
Long-term debt	6	17	18
Fair value of financial instruments	7	--	--
Other	37	95	51

Total deferred tax assets	207	320	385
Deferred tax liabilities:			
Property and equipment, principally due to nontaxable business combinations, differences in depreciation, and the expensing of intangible drilling costs for tax purposes	(2,182)	(687)	(500)
ChevronTexaco Corporation common stock	(213)	(167)	(172)
Other	(11)	(84)	(32)
Total deferred tax liabilities	(2,406)	(938)	(704)
Net deferred tax liability	$(2,199)	(618)	(319)

As shown in the above table, Devon has recognized $207 million of deferred tax assets as of December 31, 2001. Such amount consists primarily of $157 million of various carryforwards available to offset future income taxes. The carryforwards include federal net operating loss carryforwards, the majority of which do not begin to expire until 2008, state net operating loss carryforwards which expire primarily between 2002 and 2014, Canadian carryforwards which expire primarily between 2002 and 2008, International carryforwards which have no expiration and minimum tax credit carryforwards which have no expiration. The tax benefits of carryforwards are recorded as an asset to the extent that management assesses the utilization of such carryforwards to be "more likely than not." When the future utilization of some portion of the carryforwards is determined not to be "more likely than not," a valuation allowance is provided to reduce the recorded tax benefits from such assets.

Devon expects the tax benefits from the net operating loss carryforwards to be utilized between 2002 and 2010. Such expectation is based upon current estimates of taxable income during this period, considering limitations on the annual utilization of these benefits as set forth by federal tax regulations. Significant changes in such estimates caused by variables such as future oil and gas prices or capital expenditures could alter the timing of the eventual utilization of such carryforwards. There can be no assurance that Devon will generate any specific level of continuing taxable earnings. However, management believes that Devon's future taxable income will more likely than not be sufficient to utilize substantially all its tax carryforwards prior to their expiration.

9. TRUST CONVERTIBLE PREFERRED SECURITIES

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

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

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

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

10. STOCKHOLDERS' EQUITY

The authorized capital stock of Devon consists of 400 million shares of common stock, par value $.10 per share (the "Common Stock"), and 4.5 million shares of preferred stock, par value $1.00 per share. The preferred stock may be issued in one or more series, and the terms and rights of such stock will be determined by the Board of Directors.

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

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

As discussed in Note 2, there were approximately 22 million shares of Devon common stock issued on August 17, 1999, in connection with the PennzEnergy merger. Also, there were 16 million Exchangeable Shares issued on December 10, 1998, in connection with the Northstar Energy Corporation combination. As of year-end 2001, 14 million of the Exchangeable Shares had been exchanged for shares of Devon's common stock. The Exchangeable Shares have rights identical to those of Devon's common stock and are exchangeable at any time into Devon's common stock on a one-for-one basis.

Devon's Board of Directors has designated a certain number of shares of the preferred stock as Series A Junior Participating Preferred Stock (the "Series A Junior Preferred Stock") in connection with the adoption of the shareholder rights plan described later in this note. Effective January 22, 2002, the Board voted to increase the designated shares from one million to two million. At December 31, 2001, there were no shares of Series A Junior Preferred Stock issued or outstanding. The Series A Junior Preferred Stock is entitled to receive cumulative quarterly dividends per share equal to the greater of $10 or 100 times the aggregate per share amount of all dividends (other than stock dividends) declared on Common Stock since the immediately preceding quarterly dividend payment date or, with respect to the first payment date, since the first issuance of Series A Junior Preferred Stock. Holders of the Series A Junior Preferred Stock are entitled to 100 votes per share (subject to adjustment to prevent dilution) on all matters submitted to a vote of the stockholders. The Series A Junior Preferred Stock is neither redeemable nor convertible. The Series A Junior Preferred Stock ranks prior to the Common Stock but junior to all other classes of Preferred Stock.

Stock Option Plans

Devon has outstanding stock options issued to key management and professional employees under three stock option plans adopted in 1988, 1993 and 1997 (the "1988 Plan," the "1993 Plan" and the "1997 Plan"). Options granted under the 1988 Plan and 1993 Plan remain exercisable by the employees owning such options, but no new options will be granted under these plans. At December 31, 2001, there were 63,000 and 320,860 options outstanding under the 1988 Plan and the 1993 Plan, respectively.

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

101

DEVON ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
DECEMBER 31, 2001, 2000 AND 1999

The exercise price of stock options granted under the 1997 Plan may not be less than the estimated fair market value of the stock at the date of grant, plus 10% if the grantee owns or controls more than 10% of the total voting stock of Devon prior to the grant. Options granted are exercisable during a period established for each grant, which period may not exceed 10 years from the date of grant. Under the 1997 Plan, the grantee must pay the exercise price in cash or in Common Stock, or a combination thereof, at the time that the option is exercised. The 1997 Plan is administered by a committee comprised of non-management members of the Board of Directors. The 1997 Plan expires on April 25, 2007. As of December 31, 2001, there were 5,274,235 options outstanding under the 1997 Plan. There were 3,745,334 options available for future grants as of December 31, 2001.

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

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

	OPTIONS OUTSTANDING		OPTIONS EXERCIS	
				W
	NUMBER OUTSTANDING	EXERCISE PRICE	NUMBER EXERCISABLE	E
Balance at December 31, 1998	5,520,656	$ 31.768	4,079,125	$
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	$
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	$
Options granted	2,600,650	$ 62.808		
Options exercised	(1,504,691)	$ 31.133		
Options forfeited	(267,583)	$ 62.774		
Balance at December 31, 2001	8,184,330	$ 41.089	5,515,958	$

The weighted average fair values of options granted during 2001, 2000 and 1999 were $13.17, $28.73 and $12.80, respectively. The fair value of each option grant was estimated for disclosure purposes on the date of grant using the Black-Scholes Option Pricing Model with the following assumptions for 2001, 2000 and 1999, respectively: risk-free interest rates of 3.8%, 5.5% and 6%; dividend yields of 0.6%, 0.4% and 0.5%; expected lives of five, five and five years; and volatility of the price of the underlying common stock of 42.2%, 40.0% and 35.2%.

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

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

Had Devon elected the fair value provisions of SFAS No. 123 and recognized compensation expense over the vesting period based on the fair value of the stock options granted as of their grant date, Devon's 2001, 2000 and 1999 pro forma net earnings (loss) and pro forma net earnings (loss) per share would have differed from the amounts actually reported as shown in the following table. The pro forma amounts shown below do not include the effects of stock options granted prior to January 1, 1995.

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

Shareholder Rights Plan

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

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

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

11. FINANCIAL INSTRUMENTS

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

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

104

DEVON ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
DECEMBER 31, 2001, 2000 AND 1999

The following methods and assumptions were used to estimate the fair values of the financial instruments in the above table. None of Devon's financial instruments are held for trading purposes. The carrying values of cash and cash equivalents, accounts receivable and accounts payable (including income taxes payable and accrued expenses) included in the accompanying consolidated balance sheets approximated fair value at December 31, 2001, 2000 and 1999.

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

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

Interest Rate Swap Agreements - The fair values of the interest rate swaps are based on quotes obtained from the counterparty to the swap agreement.

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

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

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

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

Devon's total hedged positions as of January 31, 2002 are set forth in the following tables.

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

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

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

COSTLESS PRICE COLLARS Devon has also entered into costless price collars that set a floor and ceiling price for a portion of its 2002 and 2003 oil and natural gas production. The following tables include information on these collars. The floor and ceiling prices related to domestic oil production are based on NYMEX. The NYMEX price is the monthly average of settled prices on each trading day for West Texas Intermediate Crude oil delivered at Cushing, Oklahoma. The gas prices shown in the following table have been adjusted to a NYMEX-based price, using Devon's estimates of differentials between NYMEX and the specific regional indices upon which the collars are based. The floor and ceiling prices related to the domestic collars are based on various regional first-of-the-month price indices as published monthly by Inside FERC. The floor and ceiling prices related to the Canadian collars are based on the AECO index as published by the Canadian Gas Price Reporter.

If the applicable monthly price indices are outside of the ranges set by the floor and ceiling prices in the various collars, Devon and the counterparty to the collars will settle the difference. Any such settlements will either increase or decrease Devon's gas revenues for the period. Because Devon's gas volumes are often sold at prices that differ from the related regional indices, and due to differing Btu content of gas production, the floor and ceiling prices of the various collars do not reflect actual limits of Devon's realized prices for the production volumes related to the collars.

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

OIL PRODUCTION

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

GAS PRODUCTION

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

INTEREST RATE SWAPS Devon assumed certain interest rate swaps as a result of the Anderson acquisition. Under these interest rate swaps, Devon has swapped a floating rate for a fixed rate. Under such swaps, Devon will record a fixed rate of 6.2% on $132 million of debt in 2002, 6.3% on $97 million of debt in 2003, 6.4% on $79 million of debt in 2004 through 2006 and 6.3% on $24 million of debt in 2007.

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

12. RETIREMENT PLANS

Devon has non-contributory defined benefit retirement plans (the "Basic Plans") which include U.S. and Canadian employees meeting certain age and service requirements. The benefits are based on the employee's years of service and compensation. Devon's funding policy is to contribute annually the maximum amount that can be deducted for federal income tax purposes. Rights to amend or terminate the Basic Plans are retained by Devon.

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

In 2000, Devon established a defined benefit postretirement plan, which is unfunded, and covers substantially all current employees including former Santa Fe Snyder and PennzEnergy employees who remained with Devon. Additionally, Devon assumed responsibility for the PennzEnergy sponsored defined benefit postretirement plans, which are unfunded. The plans provide medical and life insurance benefits and are, depending on the type of plan, either contributory or non-contributory. The accounting for the health care plan anticipates future cost-sharing changes that are consistent with Devon's expressed intent to increase, where possible, contributions for future retirees.

The following table sets forth the plans' benefit obligations, plan assets, reconciliation of funded status, amounts recognized in the consolidated balance sheets and the actuarial assumptions used as of December 31, 2001, 2000 and 1999.

	PENSION BENEFITS			
	2001	2000	1999	2001
			(IN MILLIONS)	
Change in benefit obligation:				
Benefit obligation at beginning of year	$ 165	156	64	$ 32
Service cost	5	7	5	--
Interest cost	13	11	6	2

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

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

Net periodic benefit cost included the following components:

	PENSION BENEFITS			OTHER POSTRETIR BENEFITS		
	2001	2000	1999	2001	2000	19
			(IN MILLIONS)			
Service cost	$ 5	7	5	$ --	1	
Interest cost	13	11	6	2	2	
Expected return on plan assets	(13)	(13)	(7)	--	--	
Amortization of prior service cost	1	--	--	--	--	
Recognized net actuarial (gain) loss	1	--	--	--	--	
Net periodic benefit cost	$ 7	5	4	$ 2	3	

For measurement purposes, a 9% annual rate of increase in the per capita cost of covered health care benefits was assumed in 2001. The rate was assumed to decrease on a pro-rata basis annually to 5% in the year 2005 and remain at that level thereafter. Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plan. A one percentage-point change in assumed health care cost trend rates would have the following effects:

	ONE-PERCENTAGE POINT INCREASE	ONE-PE POINT
	(IN MILLIONS)	
Effect on total of service and interest cost components for 2001	$ --	$
Effect on year-end 2001 postretirement benefit obligation	$ 1	$

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 $7 million, $13 million and $3 million at the end of 2001, 2000 and 1999, respectively.

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

Devon has defined contribution plans for its Canadian employees. Devon contributes between 6% and 10% of the employee's base compensation, depending upon the employee's classification. Such contributions are subject to maximum amounts allowed under the Income Tax Act (Canada).

Devon also has a savings plan for its Canadian employees. Under the savings plan, Devon contributes an amount equal to 2% of the base salary of each employee. The employees may elect to contribute up to 4% of their salary. If such employee contributions are made, they are matched by additional Devon contributions.

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

13. COMMITMENTS AND CONTINGENCIES

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

Environmental Matters

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

Certain of Devon's subsidiaries acquired in the PennzEnergy merger are involved in matters in which it has been alleged that such subsidiaries are potentially responsible parties ("PRPs") under CERCLA or similar state legislation with respect to various waste disposal areas owned or operated by third parties. As of December 31, 2001, Devon's consolidated balance sheet included $8 million of accrued liabilities, reflected in "Other liabilities," for environmental remediation. Devon does not currently believe there is a reasonable possibility of incurring additional material costs in excess of the current accruals recognized for such environmental remediation activities. With respect to the sites in which Devon subsidiaries are PRPs, Devon's conclusion is based in large part on (i) the availability of defenses to liability, including the availability of the "petroleum exclusion" under CERCLA and similar state laws, and/or (ii) Devon's current belief that its share of wastes at a particular site is or will be viewed by the Environmental Protection Agency or other PRPs as being de minimis. As a result, Devon's monetary exposure is not expected to be material.

Royalty Matters

Numerous gas producers and related parties, including Devon, have been named in various lawsuits filed by private litigants alleging violation of the federal False Claims Act. The suits allege

that the producers and related parties used below-market prices, improper deductions, improper measurement techniques and transactions with affiliates which resulted in underpayment of royalties in connection with natural gas and natural gas liquids produced and sold from federal and Indian owned or controlled lands. The various suits have been consolidated by the United States Judicial Panel on Multidistrict Litigation for pre-trial proceedings in the matter of In re Natural Gas Royalties Qui Tam Litigation, MDL-1293, United States District Court for the District of Wyoming. Devon believes that it has acted reasonably, has legitimate and strong defenses to all allegations in the suits, and has paid royalties in good faith. Devon does not currently believe that it is subject to material exposure in association with these lawsuits and no liability has been recorded in connection therewith.

Operating Leases

The following is a schedule by year of future minimum rental payments required under operating leases that have initial or remaining noncancelable lease terms in excess of one year as of December 31, 2001:

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

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

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

Santa Fe Energy Trust

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

For any calendar quarter ending on or prior to December 31, 2002, the Trust will receive additional support payments from Devon to the extent that the Trust needs such payments to distribute $0.38 per Depository Unit per quarter. The source of such support payments is limited

111

DEVON ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
DECEMBER 31, 2001, 2000 AND 1999

to Devon's remaining royalty interest in certain of the properties conveyed to the Trust. The aggregate amount of the additional royalty payments (net of any amounts recouped) is limited to $19 million on a revolving basis. If such support payments are made, certain proceeds otherwise payable to the Trust in subsequent quarters may be reduced to recoup the amount of such support payments. Through the end of 2001, the Trust had received support payments totaling $4 million and Devon had recouped all such payments.

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

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

14. REDUCTION OF CARRYING VALUE OF OIL AND GAS PROPERTIES

Under the full cost method of accounting, the net book value of oil and gas properties, less related deferred income taxes, may not exceed a calculated "ceiling." The ceiling limitation is the discounted estimated after-tax future net revenues from proved oil and gas properties plus the lower of cost or fair value of unproved properties. The ceiling is imposed separately by country. In calculating future net revenues, current prices and costs are generally held constant indefinitely. The net book value, less deferred tax liabilities, is compared to the ceiling on a quarterly and annual basis. Any excess of the net book value, less related deferred taxes, is written off as an expense. An expense recorded in one period may not be reversed in a subsequent period even though higher oil and gas prices may have increased the ceiling applicable to the subsequent period.

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

YEAR ENDED DECEMBER 31,	
2001	1999

	Gross	Net of Taxes	Gross	Net of Taxes
	(IN MILLIONS)			
United States	$ 449	281	464	302
Canada	434	252	--	--
Egypt	33	23	--	--
China	--	--	12	8
Total	$ 916	556	476	310

The 2001 domestic and Canadian reductions were primarily the result of lower prices. Under the purchase method of accounting for business combinations, acquired oil and gas properties are recorded at fair value as of the date of purchase. Devon estimates such fair value using its estimates of future oil and gas prices. In contrast, the ceiling calculation dictates that prices in effect as of the last day of the applicable quarter are held constant indefinitely. Accordingly, the resulting value is not indicative of the true fair value of the reserves. The oil and gas properties added from the Anderson acquisition and other smaller acquisitions in 2001 were recorded at fair values that were based on expected future oil and gas prices higher than the year-end 2001 prices used to calculate the ceiling. The reduction in Egypt was the result of high finding and development costs and negative revisions to proved reserves.

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

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

15. OIL AND GAS OPERATIONS

Costs Incurred

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

TOTAL
YEAR ENDED DECEMBER 31,

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

113

DEVON ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
DECEMBER 31, 2001, 2000 AND 1999

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

CANADA

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

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

Pursuant to the full cost method of accounting, Devon capitalizes certain of its general and administrative expenses which are related to property acquisition, exploration and development activities. Such capitalized expenses, which are included in the costs shown in the preceding tables, were $77 million, $62 million and $29 million in the years 2001, 2000 and 1999, respectively.

Results of Operations for Oil and Gas Producing Activities

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

	TOTAL	
	YEAR ENDED DECEMBER 3	
	2001	2000
	(IN MILLIONS, EXCEPT PER EQUIVALENT	
Oil, gas and natural gas liquids sales	$ 2,980	2,718
Production and operating expenses	(731)	(597)
Depreciation, depletion and amortization	(838)	(663)
Amortization of goodwill	(34)	(41)
Reduction of carrying value of oil and gas properties	(1,003)	--
Income tax expense	(159)	(572)
Results of operations for oil and gas producing activities	$ 215	845
Depreciation, depletion and amortization per equivalent barrel of production	$ 6.20	5.48

115

DEVON ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
DECEMBER 31, 2001, 2000 AND 1999

	DOMESTIC	
	YEAR ENDED DECEMBER	
	2001	2000
	(IN MILLIONS, EXCEPT PER EQUIVALE	
Oil, gas and natural gas liquids sales	$ 2,260	2,168

Production and operating expenses	(512)	(463)
Depreciation, depletion and amortization	(615)	(541)
Amortization of goodwill	(34)	(41)
Reduction of carrying value of oil and gas properties	(449)	--
Income tax (expense) benefit	(267)	(446)
Results of operations for oil and gas producing activities	$ 383	677
Depreciation, depletion and amortization per equivalent barrel of production	$ 6.47	5.73

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

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

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."

116

DEVON ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
DECEMBER 31, 2001, 2000 AND 1999

Quantities of Oil and Gas Reserves

Set forth below is a summary of the changes in the net quantities of crude oil, natural gas and natural gas liquids reserves for each of the three years ended December 31, 2001. Approximately 67%, 80% and 98%, of the respective year-end 2001, 2000 and 1999 domestic proved reserves were calculated by the independent petroleum consultants of LaRoche Petroleum Consultants, Ltd. and Ryder Scott Company Petroleum Consultants. The remaining percentages of domestic reserves are based on Devon's own estimates. Approximately 43% of the year-end 2001 Canadian proved reserves were calculated by the independent petroleum consultants of Paddock Lindstrom & Associates and Gilbert Laustsen Jung Associates, Ltd. The remaining percentage of Canadian reserves are based on Devon's own estimates. All of the year-end 2000 and 1999 Canadian proved reserves were calculated by the independent petroleum consultants Paddock Lindstrom & Associates. All of the international proved reserves other than Canada as of December 31, 2001, 2000 and 1999 were calculated by the independent petroleum consultants of Ryder Scott Company Petroleum Consultants.

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

Sale of reserves	(12)	(14)	--
Proved reserves as of December 31, 2001	586	5,477	121
Proved developed reserves as of:			
December 31, 1998	180	1,282	19
December 31, 1999	301	2,501	52
December 31, 2000	261	2,631	46
December 31, 2001	324	3,948	88

DEVON ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
DECEMBER 31, 2001, 2000 AND 1999

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

DEVON ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
DECEMBER 31, 2001, 2000 AND 1999

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

	INTERNATIONAL		
	OIL (MMBBLS)	GAS (BCF)	NATURAL GAS LIQUIDS (MMBBLS)
Proved reserves as of December 31, 1998	95	37	12
Revisions of estimates	(9)	12	--
Extensions and discoveries	11	123	1
Purchase of reserves	127	6	--
Production	(9)	(9)	--
Sale of reserves	--	--	--

Proved reserves as of December 31, 1999	215	169	13
Revisions of estimates	(4)	4	(1)
Extensions and discoveries	10	32	--
Purchase of reserves	--	221	--
Production	(9)	(9)	--
Sale of reserves	(15)	(4)	--
Proved reserves as of December 31, 2000	197	413	12
Revisions of estimates	11	(31)	(1)
Extensions and discoveries	14	80	2
Purchase of reserves	18	--	--
Production	(10)	(9)	--
Sale of reserves	(1)	--	--
Proved reserves as of December 31, 2001	229	453	13
Proved developed reserves as of:			
December 31, 1998	54	35	--
December 31, 1999	58	40	--
December 31, 2000	39	36	--
December 31, 2001	33	37	--

119

DEVON ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
DECEMBER 31, 2001, 2000 AND 1999

Standardized Measure of Discounted Future Net Cash Flows

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

	TOTAL		
	DECEMBER 31,		
	2001	2000	1999
	(IN MILLIONS)		
Future cash inflows	$ 23,790	40,594	18,495
Future costs:			
Development	(2,228)	(1,635)	(1,507)
Production	(8,424)	(8,198)	(6,271)
Future income tax expense	(3,403)	(9,088)	(1,928)
Future net cash flows	9,735	21,673	8,789
10% discount to reflect timing of cash flows	(4,421)	(9,201)	(4,021)
Standardized measure of discounted future net cash flows	$ 5,314	12,472	4,768

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

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

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

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

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

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

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

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

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

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

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 2001, 2000 and 1999. The revenues reported are all from external customers.

	U.S.	CANADA	INTERNATIONAL	TOTAL
		(IN MILLIONS)		
AS OF DECEMBER 31, 2001:				
Current assets	$ 661	192	228	1,081
Property and equipment, net of accumulated depreciation, depletion and amortization	4,051	4,248	729	9,028
Goodwill, net of amortization	209	1,928	69	2,206
Other assets	826	33	10	869
Total assets	$ 5,747	6,401	1,036	13,184
Current liabilities	407	367	145	919

Long-term debt	1,987	4,602	--	6,589
Deferred tax liabilities	775	1,316	51	2,142
Other liabilities	224	20	31	275
Stockholders' equity	2,354	96	809	3,259
Total liabilities and stockholders' equity	$ 5,747	6,401	1,036	13,184
YEAR ENDED DECEMBER 31, 2001:				
REVENUES				
Oil sales	$ 586	146	226	958
Gas sales	1,571	307	12	1,890
Natural gas liquids sales	103	28	1	132
Other	78	8	9	95
Total revenues	2,338	489	248	3,075
COSTS AND EXPENSES				
Lease operating expenses	340	110	81	531
Transportation costs	59	24	--	83
Production taxes	113	3	1	117
Depreciation, depletion and amortization of property and equipment	647	166	63	876
Amortization of goodwill	34	--	--	34
General and administrative expenses	98	15	(2)	111
Expenses related to mergers	--	1	--	1
Interest expense	139	81	--	220
Effects of changes in foreign currency exchange rates	--	11	2	13
Change in fair value of financial instruments	1	1	--	2
Reduction in carrying value of oil and gas properties	449	434	120	1,003
Total costs and expenses	1,880	846	265	2,991
Earnings (loss) before income tax expense (benefit) and cumulative effect of change in accounting principle	458	(357)	(17)	84
INCOME TAX EXPENSE (BENEFIT)				
Current	29	8	34	71
Deferred	92	(145)	12	(41)
Total income tax expense (benefit)	121	(137)	46	30
Earnings (loss) before cumulative effect of change in accounting principle	337	(220)	(63)	54
Cumulative effect of change in accounting principle	49	--	--	49
Net earnings (loss)	$ 386	(220)	(63)	103
Capital expenditures	$ 1,356	3,774	196	5,326

DEVON ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
DECEMBER 31, 2001, 2000 AND 1999

	U.S.	CANADA	INTERNATIONAL	TOTAL
		(IN MILLIONS)		
AS OF DECEMBER 31, 2000:				
Current assets	$ 645	79	210	934
Property and equipment, net of accumulated depreciation, depletion and amortization	3,640	586	684	4,910
Other assets	964	--	52	1,016
Total assets	$ 5,249	665	946	6,860
Current liabilities	449	74	106	629
Long-term debt	1,902	147	--	2,049
Deferred tax liabilities	537	69	21	627
Other liabilities	259	1	18	278
Stockholders' equity	2,102	374	801	3,277
Total liabilities and stockholders' equity	$ 5,249	665	946	6,860
YEAR ENDED DECEMBER 31, 2000:				
REVENUES				
Oil sales	$ 727	116	236	1,079
Gas sales	1,305	169	11	1,485
Natural gas liquids sales	136	18	--	154
Other	58	5	3	66
Total revenues	2,226	308	250	2,784
COSTS AND EXPENSES				
Lease operating expenses	319	52	70	441
Transportation costs	42	11	--	53
Production taxes	102	1	--	103
Depreciation, depletion and amortization of property and equipment	565	65	63	693
Amortization of goodwill	41	--	--	41
General and administrative expenses	81	10	2	93
Expenses related to mergers	60	--	--	60
Interest expense	144	10	1	155
Effects of changes in foreign currency exchange rates	--	3	--	3
Total costs and expenses	1,354	152	136	1,642
Earnings before income tax expense	872	156	114	1,142
INCOME TAX EXPENSE				

Current	113	2	16	131
Deferred	185	67	29	281
Total income tax expense	298	69	45	412
Net earnings	$ 574	87	69	730
Capital expenditures	$ 893	203	184	1,280

DEVON ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
DECEMBER 31, 2001, 2000 AND 1999

	U.S.	CANADA	INTERNATIONAL	TOTAL
		(IN MILLIONS)		
AS OF DECEMBER 31, 1999:				
Current assets	$ 391	69	130	590
Property and equipment, net of accumulated depreciation, depletion and amortization	3,425	468	531	4,424
Other assets	944	--	138	1,082
Total assets	$ 4,760	537	799	6,096
Current liabilities	357	45	65	467
Long-term debt	2,077	339	--	2,416
Deferred tax liabilities (assets)	340	2	(18)	324
Other liabilities	318	3	47	368
Stockholders' equity	1,668	148	705	2,521
Total liabilities and stockholders' equity	$ 4,760	537	799	6,096
YEAR ENDED DECEMBER 31, 1999:				
REVENUES				
Oil sales	$ 332	80	149	561
Gas sales	502	114	12	628
Natural gas liquids sales	58	10	--	68
Other	15	5	1	21
Total revenues	907	209	162	1,278
COSTS AND EXPENSES				
Lease operating expenses	189	50	60	299
Transportation costs	22	12	--	34
Production taxes	43	1	1	45
Depreciation, depletion and amortization of property and equipment	309	65	32	406
Amortization of goodwill	16	--	--	16

General and administrative expenses	69	12	--	81
Expenses related to mergers	17	--	--	17
Interest expense	84	24	1	109
Effects of changes in foreign currency exchange rates	--	(13)	--	(13)
Distributions on preferred securities of subsidiary trust	7	--	--	7
Reduction of carrying value of oil and gas properties	464	--	12	476
Total costs and expenses	1,220	151	106	1,477
Earnings (loss) before income tax expense (benefit) and extraordinary item	(313)	58	56	(199)
INCOME TAX EXPENSE (BENEFIT)				
Current	15	3	5	23
Deferred	(119)	27	20	(72)
Total income tax expense (benefit)	(104)	30	25	(49)
Net earnings (loss) before extraordinary item	(209)	28	31	(150)
Extraordinary loss	(4)	--	--	(4)
Net earnings (loss)	$ (213)	28	31	(154)
Capital expenditures	$ 686	92	105	883

DEVON ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
DECEMBER 31, 2001, 2000 AND 1999

18. SUPPLEMENTAL QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

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

	2001				
	FIRST QUARTER	SECOND QUARTER	THIRD QUARTER	FOURTH QUARTER	FULL YEAR
	(IN MILLIONS, EXCEPT PER SHARE AMOUNTS)				
Oil, gas and natural gas liquids sales	$ 1,011	710	571	688	2,98
Total revenues	$ 1,024	725	586	740	3,07
Net earnings (loss)	$ 400	136	85	(518)	10
Net earnings (loss) per common share:					
Basic	$ 3.08	1.03	0.65	(4.13)	0.7

Diluted	$ 2.96	1.01	0.64	(4.13)	0.7

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

The second, third and fourth quarters of 2001 include $77 million, $10 million and $916 million, respectively, of reductions of carrying value of oil and gas properties. The after-tax effect of these expenses was $62 million, $7 million and $556 million, respectively. The per share effect of these quarterly reductions was $0.48, $0.05 and $4.42, respectively.

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

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

Mitchell Energy & Development Corp. Merger

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

	(I EXCEP
Calculation and preliminary allocation of purchase price:	

Shares of Devon common stock issued to Mitchell stockholders
Average Devon stock price

Fair value of common stock issued
Cash paid to Mitchell stockholders, calculated at $31 per outstanding common share of Mitchell

Fair value of Devon common stock and cash to be issued to Mitchell Stockholders
Plus estimated acquisition costs incurred
Plus fair value of Mitchell employee stock options assumed by Devon

Total purchase price

Plus fair value of liabilities assumed by Devon:

Current liabilities
Long-term debt
Other long-term liabilities
Deferred income taxes

Total purchase price plus liabilities assumed

Fair value of assets acquired by Devon:

Current assets
Proved oil and gas properties
Unproved oil and gas properties
Gas services facilities and equipment
Other property and equipment
Other assets
Goodwill (none deductible for income tax purposes)

Total fair value of assets acquired

Pro Forma Information

Set forth in the following tables are certain unaudited pro forma financial information as of December 31, 2001, and for the years ended December 31, 2001 and 2000. The information as of December 31, 2001, assumes the Mitchell merger had closed on such date. The information for

the years ended December 31, 2001 and 2000, has been prepared assuming the Anderson acquisition and the Mitchell merger were consummated on January 1, 2000. All pro forma information is based on estimates and assumptions deemed appropriate by Devon. The pro forma information is presented for illustrative purposes only. If the transactions had occurred in the past, Devon's operating results might have been different from those presented in the following table. The pro forma information should not be relied upon as an indication of the operating results that Devon would have achieved if the transactions had occurred on January 1, 2000. The pro forma information also should not be used as an indication of the future results that Devon will achieve after the transactions.

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

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

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

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

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

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

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

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

- Anderson had a compensation plan pursuant to which it periodically issued awards referred to as share appreciation rights under which employees could earn compensation based on increases in the market price of Anderson's stock. Anderson awarded these rights in lieu of stock

option grants. Pro forma general and administrative expenses reported in the accompanying unaudited pro forma statements of operations for the years ended December 31, 2001 and 2000 include $6 million and $5 million, respectively, of expenses related to these plans. After taxes, these plans had the effect of decreasing unaudited pro forma net earnings in the 2001 and 2000 periods by $3 million and $3 million, respectively. Devon acquired all outstanding rights as part of the Anderson acquisition. Accordingly, these rights will not affect Devon's net earnings subsequent to the closing of the Anderson acquisition.

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

- Devon's historical results of operations for the years 2001 and 2000 include $34 million and $41 million, respectively, of amortization expense for goodwill related to previous mergers. As of January 1, 2002, in accordance with new accounting pronouncements recently issued, such goodwill will cease to be amortized and, instead, will be tested for impairment at least annually. No goodwill amortization expense has been recognized in the pro forma statements of operations for the goodwill related to the Anderson acquisition and the Mitchell merger.

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

	PRO FORMA INFORMATION YEAR ENDED DECEMBER 31,	
	2001	2000

	----	----
	(IN MILLIONS, EXCEPT PER SHARE AMOUNTS AND PRODUCTION VOLUMES)	
REVENUES		
Oil sales	$ 1,232	1,384
Gas sales	3,145	2,522
Natural gas liquids sales	308	342
Gas services revenue	1,169	1,202
Other	92	47
Total revenues	5,946	5,497
COSTS AND EXPENSES		
Lease operating expenses	769	640
Transportation costs	155	119
Production taxes	149	129
Gas services costs and expenses	1,038	984
Depreciation, depletion and amortization of property and equipment	1,393	1,192
Amortization of goodwill	34	41
General and administrative expenses	202	205
Expenses related to mergers	1	60
Interest expense	508	495
Effects of changes in foreign currency exchange rates	21	3
Change in fair value of financial instruments	16	--
Reduction of carrying value of oil and gas properties	1,155	--
Total costs and expenses	5,441	3,868
Earnings before income tax expense and cumulative effect of change in accounting principle	505	1,629
INCOME TAX EXPENSE		
Current	108	173
Deferred	68	412
Total income tax expense	176	585
Earnings before cumulative effect of change in accounting principle	329	1,044
Cumulative effect of change in accounting principle	49	--
Net earnings	378	1,044
Preferred stock dividends	10	10
Net earnings applicable to common stockholders	$ 368	1,034
Net earnings before cumulative effect of change in accounting principle per average common share outstanding:		
Basic	$ 2.03	6.62

Diluted	$ 2.00	6.45
Net earnings per average common share outstanding:		
Basic	$ 2.35	6.62
Diluted	$ 2.30	6.45
Weighted average common shares outstanding--basic	157	156
Weighted average common shares outstanding--diluted	164	161
Production volumes:		
Oil (MMBbls)	58	54
Gas (Bcf)	810	708
NGLs (MMBbls)	17	16
MMBoe	210	188

130

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

Not applicable.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

The information called for by this Item 10 is incorporated herein by reference to the definitive Proxy Statement to be filed by the Company pursuant to Regulation 14A of the General Rules and Regulations under the Securities and Exchange Act of 1934 not later than April 30, 2002.

ITEM 11. EXECUTIVE COMPENSATION

The information called for by this Item 11 is incorporated herein by reference to the definitive Proxy Statement to be filed by the Company pursuant to Regulation 14A of the General Rules and Regulations under the Securities and Exchange Act of 1934 not later than April 30, 2002.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The information called for by this Item 12 is incorporated herein by reference to the definitive Proxy Statement to be filed by the Company pursuant to Regulation 14A of the General Rules and Regulations under the Securities and Exchange Act of 1934 not later than April 30, 2002.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

The information called for by this Item 13 is incorporated herein by reference to the definitive Proxy Statement to be filed by the Company pursuant to Regulation 14A of the General Rules and Regulations under the Securities and Exchange Act of 1934 not later than April 30, 2002.

131

PART IV

ITEM 14. EXHIBITS, FINANCIAL STATEMENTS AND SCHEDULES, AND REPORTS ON FORM 8-K

(a) The following documents are filed as part of this report:

1. Consolidated Financial Statements

Reference is made to the Index to Consolidated Financial Statements and Consolidated Financial Statement Schedules appearing at Item 8 on Page 69 of this report.

2. Consolidated Financial Statement Schedules

All financial statement schedules are omitted as they are inapplicable, or the required information has been included in the consolidated financial statements or notes thereto.

3. Exhibits

2.1 Offer to Purchase for Cash and Directors' Circular dated September 6, 2001 between Registrant and Anderson Exploration Ltd. (incorporated by reference to Registrant's and Devon Acquisition Corporation's Schedule 14D-1F as filed September 6, 2001).

2.2 Pre-Acquisition Agreement, dated as of August 31, 2001, between Registrant and Anderson Exploration Ltd. (incorporated by reference to Exhibit 2.2 to Registrant's Registration Statement on Form S-4, File No. 333-68694 as filed September 14, 2001).

2.3 Amended and Restated Agreement and Plan of Merger, dated as of August 13, 2001, by and among Registrant, Devon NewCo Corporation, Devon Holdco Corporation, Devon Merger Corporation, Mitchell Merger Corporation and Mitchell Energy & Development Corp. (incorporated by reference to Annex A to Registrant's Joint Proxy Statement/Prospectus of Form S-4 Registration Statement No. 333-68694 as filed August 30, 2001).

2.4 Amendment No. One, dated as of July 11, 2000, to Agreement and Plan of Merger by and among Registrant, Devon Merger Co. and Santa Fe Snyder Corporation dated as of May 25, 2000 (incorporated by reference to Exhibit 2.1 to Registrant's Form 8-K filed on July 12, 2000).

2.5 Agreement and Plan of Merger by and among Registrant, Devon Merger Co. and Santa Fe Snyder Corporation dated as of May 25, 2000 (incorporated by reference to Registrant's Registration Statement on Form S-4, File No. 333-39908).

132

2.6 Amended and Restated Agreement and Plan of Merger among Registrant, Devon Energy Corporation (Oklahoma), Devon Oklahoma Corporation and PennzEnergy Company dated as of May 19, 1999 (incorporated by reference to Exhibit 2.1 to Registrant's Form S-4, File No. 333-82903).

2.7 Amended and Restated Combination Agreement between

Registrant and Northstar Energy Corporation dated as of June 29, 1998 (incorporated by reference to Annex B to Registrant's definitive proxy statement for a special meeting of shareholders, filed November 6, 1998).

3.1 Registrant's Restated Certificate of Incorporation (incorporated by reference to Exhibit 3 to Registrant's Form 8-K filed August 18, 1999).

3.2 Registrant's Amended and Restated Bylaws (incorporated by reference to Exhibit 3.2 to Registrant's definitive proxy statement for a special meeting of shareholders filed July 21, 2000).

4.1 Form of Common Stock Certificate of Registrant (incorporated by reference to Exhibit 4.1 to Registrant's Form 8-K filed on August 18, 1999).

4.2 Rights Agreement dated as of August 17, 1999 between Registrant and BankBoston, N.A. (incorporated by reference to Exhibit 4.2 to Registrant's Form 8-K filed on August 18, 1999).

4.3 Amendment to Rights Agreement, dated as of May 25, 2000, by and between Registrant and Fleet National Bank (f/k/a BankBoston, N.A.) (incorporated by reference to Exhibit 4.2 to Registrant's definitive proxy statement for a special meeting of shareholders filed on July 21, 2000).

4.4 Amendment to Rights Agreement, dated as of October 4, 2001, by and between Registrant and Fleet National Bank (f/k/a Bank Boston, N.A.) (incorporated by reference to Exhibit 99.1 to Registrant's Form 8-K filed on October 11, 2001).

4.5 Registration Rights Agreement dated as of June 22, 2000 by and among Registrant and Morgan Stanley & Co. Incorporated and Salomon Smith Barney Inc. relating to Registrant's Zero Coupon Convertible Senior Debentures due 2020 (incorporated by reference to Exhibit 4.1 to Registrant's Form 8-K filed July 12, 2000).

4.6 Registration Rights Agreement dated December 31, 1996, by and between Registrant and Kerr-McGee Corporation (incorporated by reference to Exhibit 4.4 to Registrant's Form 8-K filed on January 14, 1997).

4.7 Registration Rights Agreement dated as of October 3, 2001 by and among Devon Financing Corporation, U.L.C., as Issuer, Registrant, as Guarantor and UBS Warburg LLC, Banc of America Securities LLC, ABN AMRO Incorporated, BMO Nesbitt Burns Corp., Credit Suisse First Boston Corporation, Deutsche Banc Alex. Brown Inc., First Union Securities, Inc., J.P. Morgan Securities Inc., RBC Dominion Securities Corporation, Salomon Smith Barney Inc., as Initial Purchasers (6.875% Notes due 2011, 7.875% Debentures due 2031) (incorporated by reference to Exhibit 4.8 to Registrant's Registration Statement on Form S-4, File No. 333-68694 as filed October 31, 2001).

4.8 Description of Capital Stock of Registrant (incorporated by reference to Exhibit 4.9 to Registrant's Form 8-K filed on August 18, 1999).

4.9 Indenture, dated as of October 3, 2001, by and among Devon Financing Corporation, U.L.C. (as issuer), Registrant (as guarantor) and The Chase Manhattan Bank (as trustee) 6.875% Notes due 2011 and 7.875% Debentures due 2031 (incorporated by reference to Exhibit 4.7 to Registrant's Registration Statement on Form S-4, File No. 333-68694 as filed October 31, 2001).

4.10 Certificate of Designations of Series A Junior Participating Preferred Stock of Registrant (incorporated by reference to Exhibit 4.3 to Registrant's Form 8-K filed on August 18, 1999).

4.11 Certificate of Designations of the 6.49% Cumulative Preferred Stock, Series A of Registrant (incorporated by reference to Exhibit 4(g) to Registrant's Form 8-K filed on August 18, 1999).

4.12 Restated Declaration of Trust of Devon Financing Trust II and Corrected Certificate of Trust of Devon Financing Trust II (incorporated by reference to Exhibits 4.5 and 4.6 of Registrant's Registration Statement on Form S-3, File Nos. 333-50034 and 333-50034-01 as filed November 16, 2000).

4.13 Form of Zero Coupon Convertible Senior Subordinated Debenture Due 2020 (incorporated by reference to Exhibit A of Exhibit 4.2 to Registrant's Form 8-K filed July 12, 2000).

4.14 Indenture dated as of June 27, 2000 between Registrant and The Bank of New York, setting forth the terms of the Zero Coupon Convertible Senior Debentures due 2020 (incorporated by reference to Exhibit 4.2 to Registrant's Form 8-K filed July 12, 2000).

134

4.15 Form of Indenture relating to senior debt securities of Registrant (incorporated by reference to Exhibit 4.10 to Registrant's Registration Statement on Form S-3, File No. 333-83156 as filed February 21, 2002).

4.16 Form of Indenture relating to subordinated debt securities of Registrant (incorporated by reference to Exhibit 4.11 to Registrant's Registration Statement on Form S-3, File No. 333-83156 as filed February 21, 2002).

4.17 Form of Indenture relating to debt securities of Devon Financing Corporation, U.L.C. (as Issuer) and Registrant (as Guarantor) (incorporated by reference to Exhibit 4.12 to Registrant's Registration Statement on Form S-3, File No. 333-83156 as filed February 21, 2002).

4.18 Form of Amended and Restated Declaration of Trust of Devon Financing Trust II (incorporated by reference to Exhibit 4.14 to Registrant's Registration Statement on Form S-3, File No. 333-83156 as filed February 21, 2002).

4.19 Form of Trust Preferred Securities Guaranty Agreement for Devon Financing Trust II (incorporated by reference to Exhibit 4.13 to Registrant's Registration Statement on Form S-3, File No. 333-83156 as filed February 21, 2002).

4.20 Senior Indenture dated as of June 1, 1999 between Santa Fe Snyder and The Bank of New York, as Trustee, relating to Santa Fe Snyder Corporation's 8.05% Senior Notes due 2004 (incorporated by reference to Exhibit 4.1 to Santa Fe Snyder Corporation's Form 8-K filed on June 15, 1999).

4.21 First Supplemental Indenture dated as of June 14, 1999 to Senior Indenture dated June 1, 1999 between Santa Fe Snyder and The Bank of New York, as Trustee, relating to Santa Fe Snyder's 8.05% Senior Notes due 2004 (incorporated by reference to Exhibit 4.2 to Santa Fe Snyder Corporation's Form 8-K filed on June 15, 1999).

4.22 Indenture dated as of June 10, 1997 between Snyder Oil Corporation (as predecessor by merger to Santa Fe Snyder Corporation) and Texas Commerce Bank National Association relating to Snyder Oil Corporation's 8.75% Senior Subordinated Notes due 2007 (incorporated by reference to Exhibit 4.1 to Snyder Oil Corporation's Form 8-K dated June 10, 1997, File No. 1-10509).

4.23 First Supplemental Indenture dated as of June 10, 1997 between Snyder Oil Corporation and Texas Commerce Bank National Association relating to Snyder Oil Corporation's 8.75% Senior Subordinated Notes due 2007 (incorporated by reference to Exhibit 4.2 to Snyder Oil Corporation's Form 8-K dated June 10, 1997, File No. 1-10509).

4.24 Second Supplemental Indenture dated as of June 10, 1997 between Snyder Oil Corporation and Texas Commerce Bank National Association relating to Snyder Oil Corporation's 8.75% Senior Subordinated Notes due 2007 (incorporated by reference to Exhibit 4.2 to Snyder Oil Corporation's Form 8-K dated June 10, 1997, File No. 1-10509).

4.25 Indenture dated as of December 15, 1992 between Registrant (as successor by merger to PennzEnergy Company, formerly Pennzoil Company) and Texas Commerce Bank National Association, Trustee setting forth the terms of the 4.90% Exchangeable Senior Debentures due 2008 and the 4.95% Exchangeable Senior Debentures due 2008 (incorporated by reference to Exhibit 4(o) to

Pennzoil Company's Form 10-K filed March 10, 1993 (SEC File No. 1-5591)).

4.26 Third Supplemental Indenture dated as of August 3, 1998 to Indenture dated as of December 15, 1992 among Registrant (as successor by merger to PennzEnergy Company, formerly Pennzoil Company) and Chase Bank of Texas, National Association, supplements the terms of the 4.90% Exchangeable Senior Debentures due 2008 (incorporated by reference to Exhibit 4(g) to PennzEnergy Company's Form 10-K for the year ended December 31, 1998).

4.27 Fourth Supplemental Indenture dated as of August 3, 1998 to Indenture dated as of December 15, 1992 among Registrant (as successor by merger to PennzEnergy Company, formerly Pennzoil Company) and Chase Bank of Texas, National Association, supplements the terms of the 4.95% Exchangeable Senior Debentures due 2008 (incorporated by reference to Exhibit 4(h) to PennzEnergy Company's Form 10-K for the year ended December 31, 1998).

4.28 Fifth Supplemental Indenture dated as of August 17, 1999 to Indenture dated as of December 15, 1992 among Registrant (as successor by merger to PennzEnergy Company, formerly Pennzoil Company) and Chase Bank of Texas, National Association supplements the terms of the 4.90% Exchangeable Senior Debentures due 2008 and the 4.95% Exchangeable Senior Debentures due 2008 (incorporated by reference to Exhibit 4.7 to Registrant's Form 8-K filed on August 18, 1999).

4.29 Indenture dated as of February 15, 1986 among Registrant (as successor by merger to PennzEnergy Company, formerly Pennzoil Company) and Mellon Bank, N.A. (incorporated by reference to Exhibit 4(a) to Pennzoil Company's Form 10-Q for the quarter ended June 30, 1986 (SEC File No. 1-5591).

4.30 First Supplemental Indenture dated as of August 17, 1999 to Indenture dated as of February 15, 1986 among Registrant (as successor by merger to PennzEnergy Company, formerly Pennzoil Company) and Chase Bank of Texas, National Association supplementing the terms of the 10.625% Debentures due 2001, 10.125% Debentures due 2009, 9.625% Notes due 1999 and 10.25% Debentures due 2005 (incorporated by reference to Exhibit 4.8 to Registrant's Form 8-K filed on August 18, 1999).

4.31 Support Agreement, dated December 10, 1998, between the Registrant and Northstar Energy Corporation (incorporated by reference to Exhibit 4.1 to Devon Energy Corporation (Oklahoma)'s (predecessor to Registrant) Form 8-K dated as of December 11, 1998).

4.32 Amending Support Agreement dated August 17, 1999, between the Registrant and Northstar Energy Corporation (incorporated by reference to Exhibit 4.5 to

Registrant's Form 8-K filed on August 18, 1999).

4.33 Exchangeable Share Provisions (incorporated by reference to Exhibit 4.2 to Registrant's Form 8-K filed December 23, 1998).

4.34 Amended Exchangeable Share Provisions dated as of August 17, 1999 (incorporated by reference to Exhibit 4.17 to Registrant's Form 10-K for the year ended December 31, 1999).

9.1 Voting and Exchange Trust Agreement, dated December 10, 1998, by and between the Registrant, Northstar Energy Corporation and CIBC Mellon Trust Company (incorporated by reference to Exhibit 9 to Registrant's Form 8-K filed on December 23, 1998).

9.2 Amending Voting and Exchange Trust Agreement, dated as of August 17, 1999, by and between Registrant, Northstar Energy Corporation and CIBC Mellon Trust Company (incorporated by reference to Exhibit 9 to Registrant's Form 8-K filed on August 18, 1999).

10.1 Amended and Restated Principal Shareholders Agreement Containing a Voting Agreement and an Irrevocable Proxy, dated as of August 13, 2001, by and among Devon Energy Corporation, George P. Mitchell and Cynthia Woods Mitchell (attached as Annex B to the Joint Proxy Statement/Prospectus of Form S-4 Registration Statement No. 333-68694 as filed August 30, 2001).

10.2 U.S. Credit Agreement, dated August 29, 2000 among the Registrant, as U.S. Borrower, Bank of America, N.A., as Administrative Agent, Banc of America Securities, LLC, as Lead Arranger, Banc One Capital Markets, Inc., as Syndication Agent, The Chase Manhattan Bank, as Documentation Agent, First Union National Bank, as Co-Documentation Agent, and Certain Financial Institutions, as Lenders for the $725 million credit facility (incorporated by reference to Exhibit 10.1 to Registrant's Form 10-K filed on March 15, 2001).

10.3 First Amendment to U.S. Credit Agreement dated March 1, 2001, among Registrant, Bank of America N.A., individually and as administrative agent, and the U.S. Lenders party to the Original Agreement (incorporated by reference to Exhibit 10.1.1 to Registrant's Form 10-Q filed on May 14, 2001).

10.4 Second Amendment to U.S. Credit Agreement dated as of June 27, 2001, among Registrant, Bank of America, N.A., individually and as administrative agent, and the U.S. Lenders party to the Original Agreement (incorporated by reference to Exhibit 10.1.2 to Registrant's Form 10-Q filed on August 14, 2001).

10.5 Third Amendment to U.S. Credit Agreement dated as of July 31, 2001, among Registrant, Bank of America, N.A., individually and as administrative agent, and the U.S.

Lenders party to the Original Agreement (incorporated by reference to Exhibit 10.4 to Registrant's Registration Statement on Form S-4, File No. 333-68694 as filed October 31, 2001).

10.6 Fourth Amendment to U.S. Credit Agreement dated as of August 13, 2001, among Registrant, Bank of America, N.A., individually and as administrative agent, and the U.S. Lenders party to the Original Agreement (incorporated by reference to Exhibit 10.5 to Registrant's Registration Statement on Form S-4, File No. 333-68694 as filed October 31, 2001).

10.7 Fifth Amendment to U.S. Credit Agreement dated as of September 21, 2001, among Registrant, Bank of America, N.A., individually and as administrative agent, and the U.S. Lenders party to the Original Agreement (incorporated by reference to Exhibit 10.6 to Registrant's Registration Statement on Form S-4, File No. 333-68694 as filed October 31, 2001).

10.8 Sixth Amendment to U.S. Credit Agreement dated as of October 5, 2001, among Registrant, Bank of America, N.A., individually and as administrative agent, and the U.S. Lenders party to the Original Agreement (incorporated by reference to Exhibit 10.7 to Registrant's Registration Statement on Form S-4, File No. 333-68694 as filed October 31, 2001).

138

10.9 Amended and Restated Investor Rights Agreement, dated as of August 13, 2001, by and among Devon Energy Corporation, Devon Holdco Corporation, George P. Mitchell and Cynthia Woods Mitchell (attached as Annex C to the Joint Proxy Statement/Prospectus of Form S-4 Registration Statement No. 333-68694 as filed August 30, 2001).

10.10 Canadian Credit Agreement dated August 29, 2000, among Northstar Energy Corporation and Devon Energy Canada Corporation, as Canadian Borrowers, Bank of America Canada, as Administrative Agent, Banc of America Securities, LLC, as Lead Arranger, BancOne Capital Markets, Inc., as Syndication Agent, The Chase Manhattan Bank, as Documentation Agent, First Union National Bank, as Co-Documentation Agent, and Certain Financial Institutions, as Lenders for the $275 million credit facility (incorporated by reference to Exhibit 10.2 to Registrant's Form 10-K filed on March 15, 2001).

10.11 First Amendment to Canadian Credit Agreement dated March 1, 2001, among Northstar Energy Corporation, Bank of America Canada, individually and as administrative agent and the Canadian Lenders party to the Original Agreement (incorporated by reference to Exhibit 10.2.1 to Registrant's Form 10-Q filed on May 14, 2001).

10.12 Second Amendment to Canadian Credit Agreement dated as of June 27, 2001, among Northstar Energy Corporation, Bank of America Canada, individually and as administrative agent, and the Canadian Lenders party to the Original Agreement (incorporated by reference to Exhibit 10.2.2 to Registrant's Form 10-Q filed on August 14, 2001).

10.13 Third Amendment to Canadian Credit Agreement dated as of July 31, 2001, among Northstar Energy Corporation, Bank of America Canada, individually and as administrative agent, and the Canadian Lenders party to the Original Agreement (incorporated by reference to Exhibit 10.8 to Registrant's Registration Statement on Form S-4, File No. 333-68694 as filed October 31, 2001).

10.14 Fourth Amendment to Canadian Credit Agreement dated as of August 13, 2001, among Northstar Energy Corporation, Bank of America Canada, individually and as administrative agent, and the Canadian Lenders party to the Original Agreement (incorporated by reference to Exhibit 10.9 to Registrant's Registration Statement on Form S-4, File No. 333-68694 as filed October 31, 2001).

10.15 Fifth Amendment to Canadian Credit Agreement dated as of September 21, 2001, among Northstar Energy Corporation, Bank of America Canada, individually and as administrative agent, and the Canadian Lenders party to the Original Agreement (incorporated by reference to Exhibit 10.10 to Registrant's Registration Statement on Form S-4, File No. 333-68694 as filed October 31, 2001).

139

10.16 Sixth Amendment to Canadian Credit Agreement dated as of October 5, 2001, among Northstar Energy Corporation, Bank of America Canada, individually and as administrative agent, and the Canadian Lenders party to the Original Agreement (incorporated by reference to Exhibit 10.11 to Registrant's Registration Statement on Form S-4, File No. 333-68694 as filed October 31, 2001).

10.17 Credit Agreement, dated as of October 12, 2001, by and among Devon Energy Corporation, Devon Financing Corporation, U.L.C., UBS AG, Stamford Branch (as Administrative Agent), and the lenders signatory thereto (incorporated by reference to Exhibit 10.3 to Registrant's Registration Statement on Form S-4, File No. 333-68694 as filed October 31, 2001).

10.18 Santa Fe Snyder Corporation 1999 Stock Compensation Retention Plan (incorporated by reference to Exhibit 10(a) to Santa Fe Snyder Corporation's Quarterly Report on Form 10-Q for the quarter ended September 30, 1999).*

10.19 Devon Energy Corporation 1997 Stock Option Plan (incorporated by reference to Exhibit A to Registrant's Proxy Statement for the 1997 Annual Meeting of Shareholders filed on April 3, 1997).*

10.20 Devon Energy Corporation 1993 Stock Option Plan (incorporated by reference to Exhibit A to Registrant's Proxy Statement for the 1993 Annual Meeting of Shareholders filed on May 6, 1993).*

140

10.21 Santa Fe Energy Resources 1990 Incentive Stock Compensation Plan, Third Amendment and Restatement (incorporated by reference to Exhibit 10(a) to Santa Fe Energy Resources, Inc.'s Quarterly Report on Form 10-Q for the quarter ended March 31, 1996).*

10.22 Santa Fe Energy Resources, Inc. Supplemental Retirement Plan effective as of December 4, 1990 (incorporated by reference to Exhibit 10(h) to Santa Fe Energy Resources, Inc.'s Annual Report on Form 10-K for the year ended December 31, 1996).*

10.23 Devon Energy Corporation 1988 Stock Option Plan (incorporated by reference to Exhibit 10.4 to Registrant's Registration Statement on Form S-8 filed on August 19, 1999, SEC File No. 333-85553).*

10.24 Supplemental Retirement Income Agreement among Devon Energy Corporation (Nevada), Registrant and John W. Nichols, dated March 26, 1997 (incorporated by reference to Exhibit 10.13 to Registrant's Form 10-Q for the quarter ended June 30, 1997).*

10.25 Supplemental Retirement Income Plan of Devon Energy Corporation among Registrant and Brian J. Jennings, J. Michael Lacey, Duke R. Ligon, Marian J. Moon, J. Larry Nichols, Darryl G. Smette and William T. Vaughn, dated August 1, 2001.*

10.26 Form of Employment Agreement between Registrant and Brian J. Jennings, J. Michael Lacey, Duke R. Ligon, Marian J. Moon, J. Larry Nichols, Darryl G. Smette and William T. Vaughn, dated January 1, 2002.*

10.27 Consulting Agreement between Registrant (as successor by merger to PennzEnergy) and Brent Scowcroft dated May 17, 1999 (incorporated by reference to Registrant's Form 10-K for the year ended December 31, 1999).*

12 Computation of ratio of earnings to combined fixed charges and preferred stock dividends

141

21 Significant Subsidiaries of Registrant

23.1 Consent of LaRoche Petroleum Consultants

23.2 Consent of Paddock Lindstrom & Associates Ltd.

23.3 Consent of Ryder Scott Company, L.P.

23.4 Consent of Gilbert Laustsen Jung Associates Ltd.

23.5 Consent of KPMG LLP

23.6 Consent of PricewaterhouseCoopers LLP

(b) Reports on Form 8-K

October 3, 2001, the Company announced that Devon Financing Corporation, U.L.C. completed a private placement of 10-year notes and 30-year debentures.

October 11, 2001, the Company and Mitchell announced that the board of directors of each company approved an amendment to the merger agreement.

October 12, 2001, the Company announced it received all necessary regulatory approvals concerning the acquisition of Anderson.

October 26, 2001, the Company announced the completion of the Anderson acquisition.

October 31, 2001, the Company announced that it had entered into various financial transactions.

November 1, 2001, the Company reported third quarter and year-to-date 2001 financial results.

November 1, 2001, the Company filed its financial statements and notes as of September 30, 2001, and for the three-month and nine-month periods ended September 30, 2001 and 2000.

November 28, 2001, the Company filed Rule 425 filings in a Form 8-K in connection with the Mitchell acquisition.

December 3, 2001, the Company filed Anderson's historical consolidated financial statements and unaudited pro forma financial information.

December 12, 2001, the Company filed forward looking statements in connection with its December 31, 2001 reserve reports of independent petroleum engineers.

December 21, 2001, the Company announced that it entered into additional hedging transactions and summarized the aggregate effects of its 2002 oil and gas hedges in place.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

DEVON ENERGY CORPORATION

March 18, 2002 By /s/ J. Larry Nichols

J. Larry Nichols,
Chairman of the Board, President and
Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

March 18, 2002	By /s/ J. Larry Nichols J. Larry Nichols Chairman of the Board, President and Chief Executive Officer
March 18, 2002	By /s/ William T. Vaughn William T. Vaughn Senior Vice President -- Finance
March 18, 2002	By /s/ Danny J. Heatly Danny J. Heatly Vice President - Accounting

143

March 18, 2002	By /s/ Thomas F. Ferguson Thomas F. Ferguson, Director
March 18, 2002	By /s/ David M. Gavrin David M. Gavrin, Director
March 18, 2002	By /s/ Michael E. Gellert Michael E. Gellert, Director
March 18, 2002	By /s/ John A. Hill John A. Hill, Director
March 18, 2002	By /s/ William J. Johnson William J. Johnson, Director
March 18, 2002	By /s/ Michael M. Kanovsky Michael M. Kanovsky, Director
March 18, 2002	By /s/ J. Todd Mitchell J. Todd Mitchell, Director
March 18, 2002	By /s/ Robert Mosbacher, Jr. Robert A. Mosbacher, Jr., Director

March 18, 2002 By /s/ Robert B. Weaver

Robert B. Weaver, Director

144

INDEX TO EXHIBITS

EXHIBIT NUMBER	DESCRIPTION
2.1	Offer to Purchase for Cash and Directors' Circular dated September 6, 2001 between Registrant and Anderson Exploration Ltd. (incorporated by reference to Registrant's and Devon Acquisition Corporation's Schedule 14D-1F as filed September 6, 2001).
2.2	Pre-Acquisition Agreement, dated as of August 31, 2001, between Registrant and Anderson Exploration Ltd. (incorporated by reference to Exhibit 2.2 to Registrant's Registration Statement on Form S-4, File No. 333-68694 as filed September 14, 2001).
2.3	Amended and Restated Agreement and Plan of Merger, dated as of August 13, 2001, by and among Registrant, Devon NewCo Corporation, Devon Holdco Corporation, Devon Merger Corporation, Mitchell Merger Corporation and Mitchell Energy & Development Corp. (incorporated by reference to Annex A to Registrant's Joint Proxy Statement/Prospectus of Form S-4 Registration Statement No. 333-68694 as filed August 30, 2001).
2.4	Amendment No. One, dated as of July 11, 2000, to Agreement and Plan of Merger by and among Registrant, Devon Merger Co. and Santa Fe Snyder Corporation dated as of May 25, 2000 (incorporated by reference to Exhibit 2.1 to Registrant's Form 8-K filed on July 12, 2000).
2.5	Agreement and Plan of Merger by and among Registrant, Devon Merger Co. and Santa Fe Snyder Corporation dated as of May 25, 2000 (incorporated by reference to Registrant's Registration Statement on Form S-4, File No. 333-39908).
2.6	Amended and Restated Agreement and Plan of Merger among Registrant, Devon Energy Corporation (Oklahoma), Devon Oklahoma Corporation and PennzEnergy Company dated as of May 19, 1999 (incorporated by reference to Exhibit 2.1 to Registrant's Form S-4, File No. 333-82903).
2.7	Amended and Restated Combination Agreement between Registrant and Northstar Energy Corporation dated as of June 29, 1998 (incorporated by reference to Annex B to Registrant's definitive proxy statement for a special meeting of shareholders, filed November 6, 1998).
3.1	Registrant's Restated Certificate of Incorporation

	(incorporated by reference to Exhibit 3 to Registrant's Form 8-K filed August 18, 1999).
3.2	Registrant's Amended and Restated Bylaws (incorporated by reference to Exhibit 3.2 to Registrant's definitive proxy statement for a special meeting of shareholders filed July 21, 2000).

EXHIBIT NUMBER	DESCRIPTION
4.1	Form of Common Stock Certificate of Registrant (incorporated by reference to Exhibit 4.1 to Registrant's Form 8-K filed on August 18, 1999).
4.2	Rights Agreement dated as of August 17, 1999 between Registrant and BankBoston, N.A. (incorporated by reference to Exhibit 4.2 to Registrant's Form 8-K filed on August 18, 1999).
4.3	Amendment to Rights Agreement, dated as of May 25, 2000, by and between Registrant and Fleet National Bank (f/k/a BankBoston, N.A.) (incorporated by reference to Exhibit 4.2 to Registrant's definitive proxy statement for a special meeting of shareholders filed on July 21, 2000).
4.4	Amendment to Rights Agreement, dated as of October 4, 2001, by and between Registrant and Fleet National Bank (f/k/a Bank Boston, N.A.) (incorporated by reference to Exhibit 99.1 to Registrant's Form 8-K filed on October 11, 2001).
4.5	Registration Rights Agreement dated as of June 22, 2000 by and among Registrant and Morgan Stanley & Co. Incorporated and Salomon Smith Barney Inc. relating to Registrant's Zero Coupon Convertible Senior Debentures due 2020 (incorporated by reference to Exhibit 4.1 to Registrant's Form 8-K filed July 12, 2000).
4.6	Registration Rights Agreement dated December 31, 1996, by and between Registrant and Kerr-McGee Corporation (incorporated by reference to Exhibit 4.4 to Registrant's Form 8-K filed on January 14, 1997).
4.7	Registration Rights Agreement dated as of October 3, 2001 by and among Devon Financing Corporation, U.L.C., as Issuer, Registrant, as Guarantor and UBS Warburg LLC, Banc of America Securities LLC, ABN AMRO Incorporated, BMO Nesbitt Burns Corp., Credit Suisse First Boston Corporation, Deutsche Banc Alex. Brown Inc., First Union Securities, Inc., J.P. Morgan Securities Inc., RBC Dominion Securities Corporation, Salomon Smith Barney Inc., as Initial Purchasers (6.875% Notes due 2011, 7.875% Debentures due 2031) (incorporated by reference to Exhibit 4.8 to Registrant's Registration Statement on Form S-4, File No. 333-68694 as filed October 31, 2001).
4.8	Description of Capital Stock of Registrant (incorporated by reference to Exhibit 4.9 to Registrant's Form 8-K filed on August 18, 1999).

4.9	Indenture, dated as of October 3, 2001, by and among Devon Financing Corporation, U.L.C. (as issuer), Registrant (as guarantor) and The Chase Manhattan Bank (as trustee) 6.875% Notes due 2011 and 7.875% Debentures due 2031 (incorporated by reference to Exhibit 4.7 to Registrant's Registration Statement on Form S-4, File No. 333-68694 as filed October 31, 2001).

EXHIBIT NUMBER	DESCRIPTION
4.10	Certificate of Designations of Series A Junior Participating Preferred Stock of Registrant (incorporated by reference to Exhibit 4.3 to Registrant's Form 8-K filed on August 18, 1999).
4.11	Certificate of Designations of the 6.49% Cumulative Preferred Stock, Series A of Registrant (incorporated by reference to Exhibit 4(g) to Registrant's Form 8-K filed on August 18, 1999).
4.12	Restated Declaration of Trust of Devon Financing Trust II and Corrected Certificate of Trust of Devon Financing Trust II (incorporated by reference to Exhibits 4.5 and 4.6 of Registrant's Registration Statement on Form S-3, File Nos. 333-50034 and 333-50034-01 as filed November 16, 2000).
4.13	Form of Zero Coupon Convertible Senior Subordinated Debenture Due 2020 (incorporated by reference to Exhibit A of Exhibit 4.2 to Registrant's Form 8-K filed July 12, 2000).
4.14	Indenture dated as of June 27, 2000 between Registrant and The Bank of New York, setting forth the terms of the Zero Coupon Convertible Senior Debentures due 2020 (incorporated by reference to Exhibit 4.2 to Registrant's Form 8-K filed July 12, 2000).
4.15	Form of Indenture relating to senior debt securities of Devon (incorporated by reference to Exhibit 4.10 to Registrant's Registration Statement on Form S-3, File No. 333-83156 as filed February 21, 2002).
4.16	Form of Indenture relating to subordinated debt securities of Registrant (incorporated by reference to Exhibit 4.11 to Registrant's Registration Statement on Form S-3, File No. 333-83156 as filed February 21, 2002).
4.17	Form of Indenture relating to debt securities of Devon Financing Corporation, U.L.C. (as Issuer) and Registrant (as Guarantor) (incorporated by reference to Exhibit 4.12 to Registrant's Registration Statement on Form S-3, File No. 333-83156 as filed February 21, 2002).
4.18	Form of Amended and Restated Declaration of Trust of Devon

	Financing Trust II (incorporated by reference to Exhibit 4.14 to Registrant's Registration Statement on Form S-3, File No. 333-83156 as filed February 21, 2002).
4.19	Form of Trust Preferred Securities Guaranty Agreement for Devon Financing Trust II (incorporated by reference to Exhibit 4.13 to Registrant's Registration Statement on Form S-3, File No. 333-83156 as filed February 21, 2002).

EXHIBIT NUMBER	DESCRIPTION
4.20	Senior Indenture dated as of June 1, 1999 between Santa Fe Snyder and The Bank of New York, as Trustee, relating to Santa Fe Snyder Corporation's 8.05% Senior Notes due 2004 (incorporated by reference to Exhibit 4.1 to Santa Fe Snyder Corporation's Form 8-K filed on June 15, 1999).
4.21	First Supplemental Indenture dated as of June 14, 1999 to Senior Indenture dated June 1, 1999 between Santa Fe Snyder and The Bank of New York, as Trustee, relating to Santa Fe Snyder's 8.05% Senior Notes due 2004 (incorporated by reference to Exhibit 4.2 to Santa Fe Snyder Corporation's Form 8-K filed on June 15, 1999).
4.22	Indenture dated as of June 10, 1997 between Snyder Oil Corporation (as predecessor by merger to Santa Fe Snyder Corporation) and Texas Commerce Bank National Association relating to Snyder Oil Corporation's 8.75% Senior Subordinated Notes due 2007 (incorporated by reference to Exhibit 4.1 to Snyder Oil Corporation's Form 8-K dated June 10, 1997, File No. 1-10509).
4.23	First Supplemental Indenture dated as of June 10, 1997 between Snyder Oil Corporation and Texas Commerce Bank National Association relating to Snyder Oil Corporation's 8.75% Senior Subordinated Notes due 2007 (incorporated by reference to Exhibit 4.2 to Snyder Oil Corporation's Form 8-K dated June 10, 1997, File No. 1-10509).
4.24	Second Supplemental Indenture dated as of June 10, 1997 between Snyder Oil Corporation and Texas Commerce Bank National Association relating to Snyder Oil Corporation's 8.75% Senior Subordinated Notes due 2007 (incorporated by reference to Exhibit 4.2 to Snyder Oil Corporation's Form 8-K dated June 10, 1997, File No. 1-10509).
4.25	Indenture dated as of December 15, 1992 between Registrant (as successor by merger to PennzEnergy Company, formerly Pennzoil Company) and Texas Commerce Bank National Association, Trustee setting forth the terms of the 4.90% Exchangeable Senior Debentures due 2008 and the 4.95% Exchangeable Senior Debentures due 2008 (incorporated by reference to Exhibit 4(o) to Pennzoil Company's Form 10-K filed March 10, 1993 (SEC File No. 1-5591)).

4.26	Third Supplemental Indenture dated as of August 3, 1998 to Indenture dated as of December 15, 1992 among Registrant (as successor by merger to PennzEnergy Company, formerly Pennzoil Company) and Chase Bank of Texas, National Association, supplements the terms of the 4.90% Exchangeable Senior Debentures due 2008 (incorporated by reference to Exhibit 4(g) to PennzEnergy Company's Form 10-K for the year ended December 31, 1998).

EXHIBIT NUMBER	DESCRIPTION
4.27	Fourth Supplemental Indenture dated as of August 3, 1998 to Indenture dated as of December 15, 1992 among Registrant (as successor by merger to PennzEnergy Company, formerly Pennzoil Company) and Chase Bank of Texas, National Association, supplements the terms of the 4.95% Exchangeable Senior Debentures due 2008 (incorporated by reference to Exhibit 4(h) to PennzEnergy Company's Form 10-K for the year ended December 31, 1998).
4.28	Fifth Supplemental Indenture dated as of August 17, 1999 to Indenture dated as of December 15, 1992 among Registrant (as successor by merger to PennzEnergy Company, formerly Pennzoil Company) and Chase Bank of Texas, National Association supplements the terms of the 4.90% Exchangeable Senior Debentures due 2008 and the 4.95% Exchangeable Senior Debentures due 2008 (incorporated by reference to Exhibit 4.7 to Registrant's Form 8-K filed on August 18, 1999).
4.29	Indenture dated as of February 15, 1986 among Registrant (as successor by merger to PennzEnergy Company, formerly Pennzoil Company) and Mellon Bank, N.A. (incorporated by reference to Exhibit 4(a) to Pennzoil Company's Form 10-Q for the quarter ended June 30, 1986 (SEC File No. 1-5591).
4.30	First Supplemental Indenture dated as of August 17, 1999 to Indenture dated as of February 15, 1986 among Registrant (as successor by merger to PennzEnergy Company, formerly Pennzoil Company) and Chase Bank of Texas, National Association supplementing the terms of the 10.625% Debentures due 2001, 10.125% Debentures due 2009, 9.625% Notes due 1999 and 10.25% Debentures due 2005 (incorporated by reference to Exhibit 4.8 to Registrant's Form 8-K filed on August 18, 1999).
4.31	Support Agreement, dated December 10, 1998, between the Registrant and Northstar Energy Corporation (incorporated by reference to Exhibit 4.1 to Devon Energy Corporation (Oklahoma)'s (predecessor to Registrant) Form 8-K dated as of December 11, 1998).
4.32	Amending Support Agreement dated August 17, 1999, between the Registrant and Northstar Energy Corporation (incorporated by reference to Exhibit 4.5 to Registrant's Form 8-K filed on August 18, 1999).

4.33	Exchangeable Share Provisions (incorporated by reference to Exhibit 4.2 to Registrant's Form 8-K filed December 23, 1998).

EXHIBIT NUMBER	DESCRIPTION
4.34	Amended Exchangeable Share Provisions dated as of August 17, 1999 (incorporated by reference to Exhibit 4.17 to Registrant's Form 10-K for the year ended December 31, 1999).
9.1	Voting and Exchange Trust Agreement, dated December 10, 1998, by and between the Registrant, Northstar Energy Corporation and CIBC Mellon Trust Company (incorporated by reference to Exhibit 9 to Registrant's Form 8-K filed on December 23, 1998).
9.2	Amending Voting and Exchange Trust Agreement, dated as of August 17, 1999, by and between Registrant, Northstar Energy Corporation and CIBC Mellon Trust Company (incorporated by reference to Exhibit 9 to Registrant's Form 8-K filed on August 18, 1999).
10.1	Amended and Restated Principal Shareholders Agreement Containing a Voting Agreement and an Irrevocable Proxy, dated as of August 13, 2001, by and among Devon Energy Corporation, George P. Mitchell and Cynthia Woods Mitchell (attached as Annex B to the Joint Proxy Statement/Prospectus of Form S-4 Registration Statement No. 333-68694 as filed August 30, 2001).
10.2	U.S. Credit Agreement, dated August 29, 2000 among the Registrant, as U.S. Borrower, Bank of America, N.A., as Administrative Agent, Banc of America Securities, LLC, as Lead Arranger, Banc One Capital Markets, Inc., as Syndication Agent, The Chase Manhattan Bank, as Documentation Agent, First Union National Bank, as Co-Documentation Agent, and Certain Financial Institutions, as Lenders for the $725 million credit facility (incorporated by reference to Exhibit 10.1 to Registrant's Form 10-K filed on March 15, 2001).
10.3	First Amendment to U.S. Credit Agreement dated March 1, 2001, among Registrant, Bank of America N.A., individually and as administrative agent, and the U.S. Lenders party to the Original Agreement (incorporated by reference to Exhibit 10.1.1 to Registrant's Form 10-Q filed on May 14, 2001).
10.4	Second Amendment to U.S. Credit Agreement dated as of June 27, 2001, among Registrant, Bank of America, N.A., individually and as administrative agent, and the U.S. Lenders party to the Original Agreement (incorporated by reference to Exhibit 10.1.2 to Registrant's Form 10-Q filed on August 14, 2001).
10.5	Third Amendment to U.S. Credit Agreement dated as of July 31, 2001, among Registrant, Bank of America, N.A., individually and as administrative agent, and the U.S. Lenders party to the Original Agreement (incorporated by reference to Exhibit 10.4 to Registrant's Registration Statement on Form S-4, File No. 333-68694 as filed October 31, 2001).

EXHIBIT NUMBER	DESCRIPTION
10.6	Fourth Amendment to U.S. Credit Agreement dated as of August 13, 2001, among Registrant, Bank of America, N.A., individually and as administrative agent, and the U.S. Lenders party to the Original Agreement (incorporated by reference to Exhibit 10.5 to Registrant's Registration Statement on Form S-4, File No. 333-68694 as filed October 31, 2001).
10.7	Fifth Amendment to U.S. Credit Agreement dated as of September 21, 2001, among Registrant, Bank of America, N.A., individually and as administrative agent, and the U.S. Lenders party to the Original Agreement (incorporated by reference to Exhibit 10.6 to Registrant's Registration Statement on Form S-4, File No. 333-68694 as filed October 31, 2001).
10.8	Sixth Amendment to U.S. Credit Agreement dated as of October 5, 2001, among Registrant, Bank of America, N.A., individually and as administrative agent, and the U.S. Lenders party to the Original Agreement (incorporated by reference to Exhibit 10.7 to Registrant's Registration Statement on Form S-4, File No. 333-68694 as filed October 31, 2001).
10.9	Amended and Restated Investor Rights Agreement, dated as of August 13, 2001, by and among Devon Energy Corporation, Devon Holdco Corporation, George P. Mitchell and Cynthia Woods Mitchell (attached as Annex C to the Joint Proxy Statement/Prospectus of Form S-4 Registration Statement No. 333-68694 as filed August 30, 2001).
10.10	Canadian Credit Agreement dated August 29, 2000, among Northstar Energy Corporation and Devon Energy Canada Corporation, as Canadian Borrowers, Bank of America Canada, as Administrative Agent, Banc of America Securities, LLC, as Lead Arranger, BancOne Capital Markets, Inc., as Syndication Agent, The Chase Manhattan Bank, as Documentation Agent, First Union National Bank, as Co-Documentation Agent, and Certain Financial Institutions, as Lenders for the $275 million credit facility (incorporated by reference to Exhibit 10.2 to Registrant's Form 10-K filed on March 15, 2001).
10.11	First Amendment to Canadian Credit Agreement dated March 1, 2001, among Northstar Energy Corporation, Bank of America Canada, individually and as administrative agent and the Canadian Lenders party to the Original Agreement (incorporated by reference to Exhibit 10.2.1 to Registrant's Form 10-Q filed on May 14, 2001).
10.12	Second Amendment to Canadian Credit Agreement dated as of June 27, 2001, among Northstar Energy Corporation, Bank of America Canada, individually and as administrative agent, and the Canadian Lenders party to the Original Agreement (incorporated by reference to Exhibit 10.2.2 to Registrant's Form 10-Q filed

on August 14, 2001).

EXHIBIT NUMBER	DESCRIPTION
10.13	Third Amendment to Canadian Credit Agreement dated as of July 31, 2001, among Northstar Energy Corporation, Bank of America Canada, individually and as administrative agent, and the Canadian Lenders party to the Original Agreement (incorporated by reference to Exhibit 10.8 to Registrant's Registration Statement on Form S-4, File No. 333-68694 as filed October 31, 2001).
10.14	Fourth Amendment to Canadian Credit Agreement dated as of August 13, 2001, among Northstar Energy Corporation, Bank of America Canada, individually and as administrative agent, and the Canadian Lenders party to the Original Agreement (incorporated by reference to Exhibit 10.9 to Registrant's Registration Statement on Form S-4, File No. 333-68694 as filed October 31, 2001).
10.15	Fifth Amendment to Canadian Credit Agreement dated as of September 21, 2001, among Northstar Energy Corporation, Bank of America Canada, individually and as administrative agent, and the Canadian Lenders party to the Original Agreement (incorporated by reference to Exhibit 10.10 to Registrant's Registration Statement on Form S-4, File No. 333-68694 as filed October 31, 2001).
10.16	Sixth Amendment to Canadian Credit Agreement dated as of October 5, 2001, among Northstar Energy Corporation, Bank of America Canada, individually and as administrative agent, and the Canadian Lenders party to the Original Agreement (incorporated by reference to Exhibit 10.11 to Registrant's Registration Statement on Form S-4, File No. 333-68694 as filed October 31, 2001).
10.17	Credit Agreement, dated as of October 12, 2001, by and among Devon Energy Corporation, Devon Financing Corporation, U.L.C., UBS AG, Stamford Branch (as Administrative Agent), and the lenders signatory thereto (incorporated by reference to Exhibit 10.3 to Registrant's Registration Statement on Form S-4, File No. 333-68694 as filed October 31, 2001).
10.18	Santa Fe Snyder Corporation 1999 Stock Compensation Retention Plan (incorporated by reference to Exhibit 10(a) to Santa Fe Snyder Corporation's Quarterly Report on Form 10-Q for the quarter ended September 30, 1999).*

EXHIBIT NUMBER	DESCRIPTION

10.19	Devon Energy Corporation 1997 Stock Option Plan (incorporated by reference to Exhibit A to Registrant's Proxy Statement for the 1997 Annual Meeting of Shareholders filed on April 3, 1997).*
10.20	Devon Energy Corporation 1993 Stock Option Plan (incorporated by reference to Exhibit A to Registrant's Proxy Statement for the 1993 Annual Meeting of Shareholders filed on May 6, 1993).*
10.21	Santa Fe Energy Resources 1990 Incentive Stock Compensation Plan, Third Amendment and Restatement (incorporated by reference to Exhibit 10(a) to Santa Fe Energy Resources, Inc.'s Quarterly Report on Form 10-Q for the quarter ended March 31, 1996).*

EXHIBIT NUMBER	DESCRIPTION
10.22	Santa Fe Energy Resources, Inc. Supplemental Retirement Plan effective as of December 4, 1990 (incorporated by reference to Exhibit 10(h) to Santa Fe Energy Resources, Inc.'s Annual Report on Form 10-K for the year ended December 31, 1996).*
10.23	Devon Energy Corporation 1988 Stock Option Plan (incorporated by reference to Exhibit 10.4 to Registrant's Registration Statement on Form S-8 filed on August 19, 1999, SEC File No. 333-85553).*
10.24	Supplemental Retirement Income Agreement among Devon Energy Corporation (Nevada), Registrant and John W. Nichols, dated March 26, 1997 (incorporated by reference to Exhibit 10.13 to Registrant's Form 10-Q for the quarter ended June 30, 1997).*
10.25	Supplemental Retirement Income Plan of Devon Energy Corporation among Registrant and Brian J. Jennings, J. Michael Lacey, Duke R. Ligon, Marian J. Moon, J. Larry Nichols, Darryl G. Smette and William T. Vaughn, dated August 1, 2001.*
10.26	Form of Employment Agreement between Registrant and Brian J. Jennings, J. Michael Lacey, Duke R. Ligon, Marian J. Moon, J. Larry Nichols, Darryl G. Smette and William T. Vaughn, dated January 1, 2002.*
10.27	Consulting Agreement between Registrant (as successor by merger to PennzEnergy) and Brent Scowcroft dated May 17, 1999 (incorporated by reference to Registrant's Form 10-K for the year ended December 31, 1999).*
12	Computation of ratio of earnings to combined fixed charges and preferred stock dividends

21	Significant Subsidiaries of Registrant
23.1	Consent of LaRoche Petroleum Consultants
23.2	Consent of Paddock Lindstrom & Associates Ltd.
23.3	Consent of Ryder Scott Company, L.P.
23.4	Consent of Gilbert Laustsen Jung Associates Ltd.
23.5	Consent of KPMG LLP
23.6	Consent of PricewaterhouseCoopers LLP

*Compensatory plans or arrangements