DEVON ENERGY CORP/DE

FORM 10-K
(Annual Report)

Filed 03/05/04 for the Period Ending 12/31/03

Address	333 W. SHERIDAN AVENUE OKLAHOMA CITY, OK 73102
Telephone	4055528183
CIK	0001090012
Symbol	DVN
SIC Code	1311 - Crude Petroleum and Natural Gas
Fiscal Year	12/31

Table of Contents

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

Form 10-K

(Mark One)

☑ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2003

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
4.90% 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 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. ☑

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Act). ☑ Yes No ☐

The aggregate market value of the voting stock held by non-affiliates of the Registrant as of June 30, 2003, was $12,148,090,102.

On February 29, 2004, 237,953,429 shares of common stock and 1,473,409 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 2004 annual meeting of stockholders — Part III

TABLE OF CONTENTS

DEFINITIONS

As used in this document:

"AECO" means the price of gas delivered onto the NOVA Gas Transmission Ltd. System.

"Bbl" or "Bbls" means barrel or barrels.

"Bcf" means billion cubic feet.

"Boe" means barrel of oil equivalent, determined by using the ratio of one Bbl of oil or NGLs to six Mcf of gas.

"Brent" means pricing point for selling North Sea crude oil.

"Btu" means British Thermal units, a measure of heating value.

"Inside FERC" refers to the publication *Inside F.E.R.C.'s Gas Market Report.*

"LIBOR" means London Interbank Offered Rate.

"MBbls" means thousand barrels.

"MMBbls" means million barrels.

"MBoe" means thousand Boe.

"MMBoe" means million Boe.

"MMBtu" means million Btu.

"Mcf" means thousand cubic feet.

"MMcf" means million cubic feet.

"NGL" or "NGLs" means natural gas liquids.

"NYMEX" means New York Mercantile Exchange.

"Oil" includes crude oil and condensate.

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

"Canada" means the division of Devon encompassing oil and gas properties located in Canada.

"International" means the division of Devon encompassing oil and gas properties that lie outside the United States and Canada.

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 Devon's future financial position, business strategy, budgets, projected revenues, 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 Devon 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 Devon's expectations ("Cautionary Statements") include, but are not limited to, Devon'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 other products or services, currency exchange rates, the weather, inflation, the availability of goods and services, drilling risks, future processing volumes and pipeline throughput, 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,” “Item 7A. Quantitative and Qualitative Disclosure About Market Risk” and elsewhere in this report. All subsequent written and oral forward-looking statements attributable to Devon, or persons acting on its behalf, are expressly qualified in their entirety by the cautionary statements. Devon assumes no duty to update or revise its forward-looking statements based on changes in internal estimates or expectations or otherwise.

PART I

Item 1. *Business*

General

Devon Energy Corporation, including its subsidiaries, ("Devon") is an independent energy company engaged primarily in oil and gas exploration, development and production, the acquisition of producing properties, the transportation of oil, gas, and NGLs and the processing of natural gas. Through its predecessors, Devon began operations in 1971 as a privately held company. In 1988, Devon'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 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 operates oil and gas properties in the United States, Canada and various regions located outside North America. Devon's North American properties are concentrated within five geographic areas. Operations in the United States are focused in the Permian Basin, the Mid-Continent, the Rocky Mountains and onshore and offshore Gulf Coast. Canadian operations are focused in the Western Canadian Sedimentary Basin in Alberta and British Columbia. Operations outside North America are located primarily in Azerbaijan, China, Egypt, and areas in West Africa, including Equatorial Guinea, Gabon and Cote d'Ivoire. In addition to its oil and gas operations, Devon has marketing and midstream operations. These include marketing natural gas, crude oil and NGLs, and the construction and operation of pipelines, storage and treating facilities and gas processing plants. (A detailed description of Devon's significant properties and associated 2003 developments can be found under "Item 2. Properties").

At December 31, 2003, Devon's estimated proved reserves were 2,089 MMBoe, of which 58% were natural gas reserves and 42% 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 $22.7 billion. After taxes, the present value was $15.9 billion. Devon is one of the largest public independent oil and gas companies based in the United States, as measured by oil and gas reserves.

Availability of Reports

Devon makes available free of charge on its internet website, www.dvn.com, its Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(a) of the Securities Exchange Act of 1934 as soon as reasonably practicable after it electronically files or furnishes them to the Securities Exchange Commission.

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 and reserves through marketing and midstream activities.

Development of Business

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 MMBoe at year-end 1987 (without giving effect to the 1998 and 2000 mergers accounted for as poolings of interests) to 2,089 MMBoe at year-end 2003.

During the same time period, proved reserves have grown from 1.31 Boe per diluted share at year-end 1987 (without giving effect to the 1998 and 2000 poolings) to 9.65 Boe per diluted share at year-end 2003. This represents a compound annual growth rate of 13%. Another measure of value per share is oil and gas production per share. Production increased from 0.18 Boe per diluted share in 1987 (without giving effect to the 1998 and 2000 poolings) to 1.05 Boe per diluted share in 2003, a compound annual growth rate of 12%.

On April 25, 2003, Devon completed its merger with Ocean Energy, Inc. (“Ocean”). In the transaction, Devon issued 0.414 shares of its common stock for each outstanding share of Ocean common stock, or a total of approximately 74 million shares. Also, Devon assumed approximately $1.8 billion of debt from Ocean. The Ocean merger added approximately 554 million Boe to Devon’s proved reserves.

Cash flow from operations was $3.8 billion for 2003. This allowed Devon to fully fund its $2.6 billion of capital expenditures, retire over $500 million in long-term debt and add almost $1 billion to cash on hand. Devon is continuing to accumulate cash with the intent to repay debt as it matures in 2004 and subsequent years.

Devon drilled almost 300 exploration wells and over 1,900 development wells during 2003. See further discussion of Devon’s 2003 exploration and drilling efforts in “Item 2. Properties.”

On January 24, 2002, Devon completed its merger with Mitchell Energy & Development Corp. (“Mitchell”). Under the terms of this merger, Devon issued approximately 30 million shares of Devon common stock and paid $1.6 billion in cash to the Mitchell stockholders. The cash portion of the merger was funded from borrowings under a $3.0 billion senior unsecured term loan credit facility. The Mitchell merger added approximately 404 million Boe to Devon’s proved reserves.

On October 15, 2001, Devon acquired Anderson Exploration Ltd. (“Anderson”) for approximately $3.5 billion in cash. The Anderson acquisition added approximately 534 million Boe to Devon’s proved reserves.

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

The remaining $3 billion of the $6 billion of long-term debt was borrowed under a credit facility that bears interest at floating rates. As of December 31, 2003, $2.4 billion of the original $3 billion balance had been retired. The primary sources of the repayments were the issuance of $1.5 billion of debt securities, of which $1.3 billion was used to pay down the credit facility with the remainder used to pay down other debt, and $1.4 billion from the sale of certain oil and gas properties, of which $1.1 billion was used to pay down the credit facility. As of December 31, 2003, the balance outstanding under the term loan credit facility was $0.6 billion at an average rate of 2.2%. The terms of this facility require repayment of the remaining debt balance at maturity in October 2006.

Financial Information about Segments and Geographical Areas

Notes 17 and 18 to the consolidated financial statements included in “Item 8. Financial Statements and Supplementary 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 2004 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 basin of Canada and in Brazil, China, Egypt, Russia, Syria and West Africa outside North America.

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

Total Properties

	Development Wells						Exploratory Wells					
	Gross(1)			Net(2)			Gross(1)			Net(2)		
	Productive	Dry	Total	Productive	Dry	Total	Productive	Dry	Total	Productive	Dry	Total
1999	654	19	673	384.96	7.85	392.81	111	36	147	77.56	23.41	100.97
2000	1,095	20	1,115	600.63	10.55	611.18	166	47	213	121.02	32.69	153.71
2001	1,208	46	1,254	760.88	29.95	790.83	236	55	291	188.53	34.88	223.41
2002	1,382	27	1,409	1,035.47	19.72	1,055.19	217	59	276	148.38	41.24	189.62
2003	1,884	52	1,936	1,267.19	36.83	1,304.02	232	61	293	152.87	38.02	190.89
Total	6,223	164	6,387	4,049.13	104.90	4,154.03	962	258	1,220	688.36	170.24	858.60

United States Properties

	Development Wells						Exploratory Wells					
	Gross(1)			Net(2)			Gross(1)			Net(2)		
	Productive	Dry	Total	Productive	Dry	Total	Productive	Dry	Total	Productive	Dry	Total
1999	547	8	555	345.35	3.80	349.15	71	9	80	51.91	5.78	57.69
2000	890	13	903	512.18	6.80	518.98	95	11	106	80.09	7.41	87.50
2001	961	19	980	638.26	12.91	651.17	148	17	165	122.61	11.53	134.14
2002	933	7	940	725.79	4.67	730.46	21	18	39	19.60	12.00	31.60
2003	1,250	31	1,281	850.06	23.00	873.06	22	22	44	14.99	12.14	27.13
Total	4,581	78	4,659	3,071.64	51.18	3,122.82	357	77	434	289.20	48.86	338.06

Canadian Properties

	Development Wells						Exploratory Wells					
	Gross(1)			Net(2)			Gross(1)			Net(2)		
	Productive	Dry	Total	Productive	Dry	Total	Productive	Dry	Total	Productive	Dry	Total
1999	65	9	74	29.61	3.45	33.06	39	23	62	25.15	16.03	41.18
2000	130	6	136	68.74	3.25	71.99	70	27	97	40.60	19.27	59.87
2001	163	26	189	100.91	16.53	117.44	82	21	103	63.96	14.05	78.01
2002	408	20	428	300.93	15.05	315.98	196	37	233	128.78	27.47	156.25
2003	586	20	606	399.48	13.33	412.81	210	34	244	137.88	23.90	161.78
Total	1,352	81	1,433	899.67	51.61	951.28	597	142	739	396.37	100.72	497.09

International Properties

	Development Wells						Exploratory Wells					
	Gross(1)			Net(2)			Gross(1)			Net(2)		
	Productive	Dry	Total	Productive	Dry	Total	Productive	Dry	Total	Productive	Dry	Total
1999	42	2	44	10.00	0.60	10.60	1	4	5	0.50	1.60	2.10
2000	75	1	76	19.71	0.50	20.21	1	9	10	0.33	6.01	6.34
2001	84	1	85	21.71	0.51	22.22	6	17	23	1.96	9.30	11.26
2002	41	—	41	8.75	—	8.75	—	4	4	—	1.77	1.77
2003	48	1	49	17.65	0.50	18.15	—	5	5	—	1.98	1.98
Total	290	5	295	77.82	2.11	79.93	8	39	47	2.79	20.66	23.45

(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.

As of December 31, 2003, Devon was participating in the drilling of 97 gross (61.46 net) wells in the U.S., 41 gross (29.36 net) wells in Canada and 39 gross (12.53 net) wells internationally. Of these wells, through February 1, 2004, 43 gross (30.62 net) wells in the U.S., 36 gross (26.14 net) wells in Canada, and 6 gross (2.23 net) wells internationally had been completed as productive. An additional 3 gross (1.20 net) wells in the U.S. and 1 gross (1.00 net) well in Canada 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 shipped to storage, refining or pipeline facilities.

No purchaser accounted for over 10% of Devon's revenues in 2003.

Oil and Natural Gas Marketing

The spot market for oil and gas 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 financial hedging arrangements or firm delivery commitments with a portion of its oil and gas production. These activities are intended to support targeted price levels and to manage Devon's exposure to price fluctuations. (See "Item 7A. Quantitative and Qualitative Disclosures About Market Risk.")

Oil Marketing. Devon's oil production is sold under both long-term (one year or more) and short-term (less than one year) agreements at prices negotiated with third parties.

Natural Gas Marketing. Devon's gas production is also sold under both long-term and short-term agreements at prices negotiated with third parties. Although exact percentages vary daily, as of February 2004 approximately 78% 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 19% 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: 1% under short-term agreements and 2% under long-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.

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 or hot summers 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 international locations in which it operates.

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, pipelines, 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. Devon considers the cost of environmental protection a necessary and manageable part of its business. Devon 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 Devon's leases in southeast New Mexico, Montana 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 2003 concerning such matters were immaterial, but Devon cannot predict with any reasonable degree of certainty its future exposure concerning such matters.

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. Devon considers the cost of safety and health compliance a necessary and manageable part of its business. Devon has been able to plan for and comply with new initiatives without materially altering its operating strategies.

Devon maintains 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 liabilities associated with these activities, accruals have been established when reasonable estimates are possible. Such accruals primarily include estimated costs associated with remediation. Devon has not used discounting in determining its accrued liabilities for environmental remediation, and no material claims for possible recovery from third party insurers or other parties related to environmental costs have been recognized in Devon's consolidated financial statements. Devon adjusts the accruals when new remediation responsibilities are discovered and probable costs become estimable, or when current remediation estimates must be adjusted to reflect new information.

Certain of Devon's subsidiaries acquired in past mergers are involved in matters in which it has been alleged that such subsidiaries are potentially responsible parties ("PRPs") under CERCLA or similar state legislation with respect to various waste disposal areas owned or operated by third parties. As of December 31, 2003, Devon's consolidated balance sheet included $9 million of non-current accrued liabilities, reflected in "Other liabilities," related to these and other environmental remediation liabilities.

Devon does not currently believe there is a reasonable possibility of incurring additional material costs in excess of the current accruals recognized for such environmental remediation activities. With respect to the sites in which Devon subsidiaries are PRPs, Devon's conclusion is based in large part on (i) Devon's participation in consent decrees with both other PRPs and the Environmental Protection Agency, which provide for performing the scope of work required for remediation and contain covenants not to sue as protection to the PRPs, (ii) participation in groups as a *de minimis PRP*, and (iii) the availability of other defenses to liability. As a result, Devon's monetary exposure is not expected to be material.

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.

Exploration and Production. Devon's Canadian operations are subject to federal and provincial governmental regulation. Such regulation include requiring licenses for the drilling of wells, regulating the location of wells and the method and ability to produce wells, surface usage and the restoration of land upon which wells have been drilled, the plugging and abandoning of wells and the transportation of production from wells. Devon's Canadian operations are also subject to various conservation regulations, including the regulation of the size of spacing units, the number of wells which may be drilled in a unit, the unitization or pooling of oil and gas properties, the rate of production allowable from oil and gas wells, and the ability to produce oil and gas. In Canada, the effect of such regulation 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.

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, British Columbia and Saskatchewan 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, natural gas and NGLs 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 Government of Canada. 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 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 2003 concerning such matters were immaterial, but Devon cannot predict with any reasonable degree of certainty its future exposure concerning such matters.

Kyoto Protocol. In December 2002 the Government of Canada ratified the Kyoto Protocol. This protocol calls for Canada to reduce its greenhouse gas emissions to 6 percent below 1990 levels during the period between 2008 and 2012. The protocol will only become legally binding when it is ratified by at least 55 countries, covering at least 55 percent of the emissions addressed by the protocol. At this time, it is uncertain if the protocol will in fact be ratified. If the protocol becomes legally binding, it is expected to affect the operation of all industries in Canada, including the oil and gas industry. As details of the implementation of emissions reduction initiatives related to this protocol have yet to be announced, the effect on Devon cannot be determined at this time.

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 exploration, 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 operating licenses or 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, seismic, drilling and production 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 acquiring seismic data; drilling 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.

Production Sharing Contracts. Many of Devon's international licenses are governed by Production Sharing Contracts (PSC) between the concessionaires and the granting government agency. PSCs are contracts that define and regulate the framework for investments, revenue sharing, and taxation of mineral interests in foreign countries. Unlike most domestic leases, PSCs have defined production terms and time limits of generally 30 years. Many PSCs allow for recovery of investments including carried government percentages. PSCs generally contain sliding scale revenue sharing provisions. For example, at either higher production rates or higher cumulative rates of return, PSCs allow governments to generally retain higher fractions of revenue.

Environmental Regulations. Various government laws and regulations concerning the discharge of incidental materials into the environment, the generation, storage, transportation and disposal of waste 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 seismic acquisition, drilling or construction activities. Such regulations also typically include requirements to develop emergency response plans, waste management plans, environmental protection 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.

Employees

As of December 31, 2003, Devon's staff consisted of 3,924 full-time employees. Devon believes that it has good labor relations with its employees.

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 Devon'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, to a lesser extent, overriding royalty, volumetric production payments, foreign government concessions, mineral and net profits interests and other forms of direct and indirect ownership in oil and gas properties.

Devon also has certain midstream assets, including natural gas and NGL processing plants and pipeline systems. Devon's most significant midstream assets are its 3,100 mile Bridgeport pipeline system and 650 MMcf per day Bridgeport gas processing plant located in North Texas.

Proved Reserves and Estimated Future Net Revenue

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

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

"Prepared" reserves are those estimates of quantities of reserves which were prepared by an independent petroleum consultant. "Audited" reserves are those quantities of reserves which were estimated by Devon employees and audited by an independent petroleum consultant.

The domestic reserves were evaluated by the independent petroleum consultants of LaRoche Petroleum Consultants, Ltd. and Ryder Scott Company, L.P. in each of the years presented. The Canadian reserves were evaluated by the independent petroleum consultants of AJM Petroleum

Consultants in 2003 and 2002, and Paddock Lindstrom & Associates and Gilbert Laustsen Jung Associates, Ltd. in 2001. The International reserves were evaluated by the independent petroleum consultants of Ryder Scott Company, L.P. in each of the years presented.

Devon follows what it believes to be a rational approach to not only recording oil and gas reserves, but also to subjecting these reserves to reviews by independent petroleum consultants. The reserve estimates for all of our Gulf of Mexico and international properties are prepared by an independent petroleum consulting firm every year (excluding 2% of Devon's 2003 international reserves that were estimated by in-house engineers). In Canada, another independent petroleum consulting firm prepares a rolling one-third of our properties each year so that the reserve estimates for all the Canadian properties are prepared by outside engineers over a three-year cycle.

For the U.S. onshore properties, reserve estimates of individually significant properties are either prepared or audited by an independent petroleum consulting firm, while estimates of minor properties are prepared by in-house engineers. This approach results in independent engineers preparing or auditing over 50% of our U.S. onshore reserves each year.

Over any three-year period, more than 95% of Devon's company-wide reserve estimates are prepared or audited by an independent petroleum consulting firm. Devon believes this approach provides a high degree of assurance about the validity of our reserve estimates. This is evidenced by the fact that in the past four years, Devon's annual revisions to its reserve estimates have averaged approximately 2% of the previous year's estimate.

The following table sets forth Devon's estimated proved reserves and the related estimated future net revenues, pre-tax 10% Present Value and after-tax standardized measure of discounted future net cash flows as of December 31, 2003. These estimates correspond with the method used in presenting the "Supplemental Information on Oil and Gas Operations" in Note 18 to Devon's Consolidated Financial Statements included herein.

	Total Proved Reserves	Proved Developed Reserves	Proved Undeveloped Reserves
Total Reserves			
Oil (MMBbls)	661	408	253
Gas (Bcf)	7,316	5,980	1,336
NGL (MMBbls)	209	179	30
MMBoe(1)	2,089	1,584	505
Pre-tax Future Net Revenue ($ millions)(2)	40,637	30,920	9,717
Pre-tax 10% Present Value ($ millions)(2)	22,652	17,209	5,443
Standardized measure of discounted future net cash flows ($ millions)(3)	15,921		
U.S. Reserves			
Oil (MMBbls)	212	171	41
Gas (Bcf)	4,884	3,935	949
NGL (MMBbls)	161	136	25
MMBoe(1)	1,187	964	223
Pre-tax Future Net Revenue ($ millions)(2)	23,786	19,301	4,485
Pre-tax 10% Present Value ($ millions)(2)	13,345	10,829	2,516
Standardized measure of discounted future net cash flows ($ millions)(3)	9,503		

	Total Proved Reserves	Proved Developed Reserves	Proved Undeveloped Reserves
Canadian Reserves			
Oil (MMBbls)	148	123	25
Gas (Bcf)	2,297	1,964	333
NGL (MMBbls)	48	43	5
MMBoe(1)	579	493	86
Pre-tax Future Net Revenue ($ millions)(2)	10,881	9,264	1,617
Pre-tax 10% Present Value ($ millions)(2)	5,930	5,048	882
Standardized measure of discounted future net cash flows ($ millions)(3)	4,123		
International Reserves			
Oil (MMBbls)	301	114	187
Gas (Bcf)	135	81	54
NGL (MMBbls)	—	—	—
MMBoe(1)	323	127	196
Pre-tax Future Net Revenue ($ millions)(2)	5,970	2,355	3,615
Pre-tax 10% Present Value ($ millions)(2)	3,377	1,332	2,045
Standardized measure of discounted future net cash flows ($ millions)(3)	2,295		

(1) Gas reserves are converted to Boe 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. NGL reserves are converted to Boe on a one-to-one basis with oil. The respective prices of gas and oil are affected by market conditions and other factors in addition to relative energy content.

(2) 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 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, 2003. 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 $27.55 per Bbl of oil, $5.18 per Mcf of natural gas and $21.22 per Bbl of NGLs. These prices compare to December 31, 2003, New York Mercantile Exchange prices of $32.52 per Bbl for crude oil and $5.97 per MMBtu for natural gas.

(3) See Note 18 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 Canadian Securities Regulators and (ii) in filings with the Department of Energy ("DOE"). Reserve estimates filed by Devon with the SEC and Canadian Securities Regulators 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, 2003. 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, 2003, 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, 2003:

	Oil Wells		Gas Wells		Total Wells	
	Gross(1)	Net(2)	Gross(1)	Net(2)	Gross(1)	Net(2)
U.S.	10,466	3,591	15,247	9,738	25,713	13,329
Canada	2,686	1,763	4,117	2,410	6,803	4,173
International	507	222	4	2	511	224
Total	13,659	5,576	19,368	12,150	33,027	17,726

(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.

Developed and Undeveloped Acreage

The following table sets forth Devon’s developed and undeveloped oil and gas lease and mineral acreage as of December 31, 2003.

	Developed		Undeveloped	
	Gross(1)	Net(2)	Gross(1)	Net(2)
	(In thousands)			
United States				
Permian Basin	620	330	1,102	506
Mid-Continent	995	677	830	405
Rocky Mountains	779	499	1,745	885
Gulf Offshore	894	473	3,142	1,548
Gulf Coast Onshore	1,103	641	913	538
Total U. S.	4,391	2,620	7,732	3,882
Canada	3,740	2,335	14,610	9,935
International	595	323	23,549	12,051
Grand Total	8,726	5,278	45,891	25,868

(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.

Operation of Properties

The day-to-day operation 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 18,037 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. 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 North American properties are concentrated within five geographic areas. Operations in the United States are focused in the Permian Basin, the Mid-Continent, the Rocky Mountains and onshore and offshore Gulf Coast regions. Canadian operations are focused in the Western Canadian Sedimentary Basin in Alberta and British Columbia. Operations outside North America currently include Azerbaijan, Brazil, China, Egypt, Indonesia, Russia, Syria, and areas in West Africa, including Equatorial Guinea, Gabon, Cote d'Ivoire, Nigeria and Angola. Maintaining a tight geographic focus in selected core areas has allowed Devon to improve operating and capital efficiency.

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, 2003.

	Oil (MMBbls)	Gas (Bcf)	NGLs (MMBbls)	MMBoe(1)	MMBoe %(2)	10% Present Value (In millions)(3)	10% Present Value %(4)	Standardized Measure of Discounted Future Net Cash Flows (In millions)(5)
United States								
Permian Basin	92	351	17	167	8.0%	$ 1,825	8.0%	
Mid-Continent	4	1,707	102	390	18.7%	3,481	15.4%	
Rocky Mountain	21	1,021	8	200	9.6%	2,128	9.4%	
Gulf Offshore	81	702	5	203	9.7%	3,405	15.0%	
Gulf Coast Onshore	14	1,103	29	227	10.9%	2,506	11.1%	
Total U.S.	212	4,884	161	1,187	56.9%	13,345	58.9%	$ 9,503
Canada								
Total(6)	148	2,297	48	579	27.7%	5,930	26.2%	4,123
International								
Total	301	135	—	323	15.4%	3,377	14.9%	2,295
Grand Total	661	7,316	209	2,089	100.0%	$22,652	100.0%	$15,921

(1) Gas reserves are converted to Boe 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. NGL reserves are converted to Boe on a one-to-one basis with oil. 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) Determined in accordance with Statement of Financial Accounting Standards No. 69, *Disclosures about Oil and Gas Producing Activities* ("SFAS No. 69"), except that no effect is given to future income taxes.

(4) Percentages which present value for the basin or region bears to total present value for all proved reserves.

(5) Determined in accordance with SFAS No. 69.

(6) Canadian dollars converted to U.S. dollars at the rate of $1 Canadian: $0.7738 U.S.

United States

Permian Basin

Devon's Permian Basin assets are located in portions of Southeast New Mexico and West Texas. These assets include conventional oil and gas properties from a wide variety of geologic formations and productive depths. The Permian Basin represented 8% of Devon's proved reserves at December 31, 2003.

Devon's leasehold position in Southeast New Mexico encompasses more than 102,000 acres of developed lands and 237,000 acres of undeveloped land and minerals. Historically, Devon has been a very active operator in this area developing gas from the high productivity Morrow formation and oil in the lower risk Delaware formation.

In the West Texas area of the Permian Basin, Devon maintains a base of oil production with long-life reserves. Many of these reserves are from both operated and non-operated positions in large enhanced oil recovery units such as the Wasson ODC Unit, the Willard Unit, the Reeves Unit, the North Welch Unit and the Anton Irish (Clearfork) Unit. These oil-producing units often exhibit low decline rates. Devon also owns a significant acreage position in West Texas with over 194,000 acres of developed lands and over 224,000 acres of undeveloped land and minerals at December 31, 2003.

Mid-Continent

The Mid-Continent region includes portions of Texas, Oklahoma and Kansas. These areas encompass a wide variety of geologic formations and productive depths and produce both oil and natural gas. Devon's Mid-Continent production has historically come from conventional oil and gas properties. However, the Barnett Shale, acquired in our 2002 merger with Mitchell Energy, is a non-conventional gas resource. The Mid-Continent region represented 19% of Devon's proved reserves at December 31, 2003. Approximately 76% of Devon's proved reserves in the Mid-Continent area are in the Barnett Shale.

The Barnett Shale, Devon's largest producing field, 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 has yielded a low-risk and highly profitable natural gas operation. Devon holds 525,000 net acres and nearly 1,600 producing wells in the Barnett Shale. Devon's average working interest is approximately 95%.

Devon has experienced success extracting gas from the Barnett Shale by using light sand fracturing. Light sand fracturing yields better results than earlier techniques, is less expensive and can be used to complete new wells and to refracture existing wells. Refractured wells often exceed their original flow rates. Devon is also applying horizontal drilling and closer well spacing to further enhance the value of the Barnett Shale.

Devon's marketing and midstream operations transport and process its Barnett Shale production along with Barnett Shale production from unrelated third parties. The transport system consists of approximately 3,100 miles of pipeline, a 650 MMcf per day gas processing plant, and a 15,000 Bbls per day NGL fractionator.

In 2004, Devon plans to drill a total of 192 new Barnett Shale wells including 94 horizontals and 98 verticals. More than half of the horizontal wells will be drilled outside the core development area in an

effort to further expand the productive area of the field. The Barnett Shale is expected to continue to be an important producing area for Devon for the foreseeable future. Current production from the Barnett Shale is approximately 428 MMcf and 24,100 Bbls of oil and NGLs per day net.

Rocky Mountains

Devon's operations in the Rocky Mountain region include properties in Wyoming, Montana, Utah, and Northern New Mexico. These assets include conventional oil and gas properties and coalbed methane projects. As of December 31, 2003, the Rocky Mountain region comprised 9% of Devon's proved reserves.

Approximately 38% of Devon's proved reserves in the Rocky Mountains are from coalbed methane. Devon began producing coalbed methane in the San Juan Basin of New Mexico in the mid-1980s and began drilling coalbed methane wells in the Powder River Basin of Wyoming in 1998. As of December 31, 2003, Devon has drilled 1,600 coalbed methane wells in the Powder River Basin. Devon's net coalbed methane gas production from the basin was approximately 88 MMcf per day as of December 31, 2003, and Devon plans to drill 110 new wells in the Powder River Basin in 2004. Current production in the basin is primarily from the Wyodak coal formation. Development of the deeper Big George formation could significantly expand the coalbed methane play into the western portion of the Powder River Basin. The recently approved federal Environmental Impact Statement should facilitate development of the deeper formation. Eighty-five of the wells planned in 2004 target these deeper coals.

Devon's most significant conventional gas project in the Rocky Mountains region is the Washakie field in Wyoming. Devon is continuing to develop and grow production from this field. In 2003, Devon drilled 38 wells and plans to drill another 40 wells in 2004. Devon has interests in over 200,000 acres. Devon's current net production from Washakie is approximately 81 MMcf and 1,000 Bbls of oil and NGLs per day.

Gulf Coast

Devon's Gulf Coast properties are located in South and East Texas, Louisiana and Mississippi. Most of the wells in the region are completed in conventional sandstone formations. At December 31, 2003, the Gulf Coast accounted for approximately 10% of Devon's proved reserves.

Devon's operations in South Texas have focused on exploration in the Edwards, Wilcox and Frio/ Vicksburg formations. Devon has high working interests, up to 100%, in several producing fields.

East Texas is an important conventional gas producing region for Devon. Carthage/ Bethany and Groesbeck are two of the primary producing areas. Wells produce from the Cotton Valley sands, the Travis Peak sands and from shallower sands and carbonates. Devon operates over 1,300 producing wells in East Texas and is currently employing a five-rig drilling and recompletion program to continue low-risk, infill development throughout the area. Devon's current net production from east Texas is about 187 MMcf and 8,000 Bbls of oil and NGLs per day.

Gulf of Mexico

The offshore Gulf of Mexico accounted for 17% of Devon's 2003 production and 11% of year-end proved reserves. Devon is among the largest independent oil and gas producers in the Gulf of Mexico and operates 450 platforms and caissons. The 2003 merger with Ocean more than tripled Devon's Gulf reserves. Gulf of Mexico operations are typically differentiated by water depth. The shelf is defined by water depths of 600 feet or less. The deepwater is at depths beyond 600 feet. Devon has active development and drilling programs ongoing in both the shelf and deepwater areas.

In the Ocean merger, Devon acquired interests in the Nansen/ Boomvang complex in the East Breaks area of the deepwater Gulf of Mexico. Devon acquired a 50% working interest in the Nansen field and a 20% interest in the Boomvang field. Ocean established oil and natural gas production at Nansen/ Boomvang in 2002. The Nansen and Boomvang production spars have a combined daily production

capacity of 80,000 Bbls of oil and 400 MMcf of gas. Devon's share of current production from the fields is about 21,000 Bbls of oil and 120 MMcf of gas per day.

Ocean had two additional deepwater development projects under construction in 2003. Redhawk (Garden Banks 876) is expected to commence production in the second half of 2004. Devon has a 50% working interest in Redhawk and estimates net production at about 10,000 Boe per day. Magnolia (Garden Banks 783) is expected to commence production near year-end 2004. Devon has a 25% working interest in this project. Net production is estimated at between 9,000 and 12,000 Boe per day.

In the deepwater of the Gulf of Mexico, Devon drilled two exploratory discovery wells in 2003. The Sturgis well (Atwater Valley 182) found more than 100 net feet of oil pay sands. Sturgis, in 3,700 feet of water, was the second well in Devon's four-well joint venture with ChevronTexaco. Upon completion of the fourth well, Devon will earn a 25% working interest in 71 deepwater blocks. The fourth well is planned for early 2004.

The second deepwater discovery in 2003 was at St. Malo (Walker Ridge 678). St. Malo, in 6,900 feet of water, encountered more than 450 net feet of oil pay. St. Malo and the previously announced Cascade discovery (Walker Ridge 206) are located in the lower Tertiary trend. Based on early evidence, the lower Tertiary trend may hold significant reserve potential. Devon plans to drill appraisal wells to better define the St. Malo and Cascade discoveries in the first half of 2004. Devon also plans to drill an appraisal well to the Sturgis discovery and additional lower Tertiary exploratory wells during 2004.

In 2003, Devon had a notable shelf discovery on its Grays prospect (Galveston block 424). Three producing wells from this discovery were brought on production in early 2004 at approximately 27 MMcf per day net to Devon's interest.

The federal government is encouraging Gulf of Mexico operators to drill deep shelf wells, wells drilled on the shelf to a depth greater than 15,000 feet, through a reduced royalty incentive program. Devon plans to drill 10 to 12 deep shelf wells in 2004.

Canada

Devon is among the largest independent oil and gas producers in Canada and operates in most of the producing basins in Western Canada. As of December 31, 2003, 28% of Devon's proved reserves were Canadian. Many of the Canadian basins where Devon operates are accessible for drilling only in the winter when the ground is frozen. Consequently, the winter season, from December through March, is the most active drilling period.

Devon expects to drill about 400 wells in the 2003-2004 winter program and spend $360 million, or nearly half of the full year Canadian capital budget. The winter drilling is focused on three major areas: the Deep Basin, Northeastern British Columbia and the Northern Plains of Alberta. In the Deep Basin, plans call for 106 wells compared with 71 wells last winter. In Northeastern B.C., 93 wells are planned, compared with 73 the previous winter. In the Northern Plains, we expect to drill more than 100 wells this winter, compared with 76 wells a year ago.

The Anderson acquisition in 2001 significantly strengthened Devon's holdings in the Deep Basin of Western Alberta. Devon had sought for years to obtain a significant acreage position in the Deep Basin, but other operators, including Anderson, already controlled most of the acreage. As a result of the Anderson acquisition, Devon now holds over 800,000 net acres in the Deep Basin. The profitability of Devon's operations in the Deep Basin is enhanced by its ownership in nine gas processing plants in the area. Devon plans to drill about 193 total wells in the Deep Basin in 2004. Deep Basin reservoirs tend to be rich in liquids, producing up to 100 barrels of NGLs with each MMcf of gas.

In 2002, Devon commenced production from the first of several wells it has drilled in the Grizzly Valley area of the Foothills Region of Northeastern British Columbia. Due to gas pipeline and processing limitations, initial production was limited to about 10 MMcf of gas per day. However, a pipeline extension completed in 2003 allowed Devon to increase production from this area to about 30 MMcf per day. With

the pipeline extension complete, Devon can continue to tie in additional wells in the area. Net production from the entire Foothills region is approximately 130 MMcf of gas per day.

Devon also acquired from Anderson approximately 1.5 million net acres in the MacKenzie Delta region and the shallow waters of the Beaufort Sea in Northern Canada. In 2002, a Devon well in the MacKenzie Delta encountered over 110 feet of natural gas pay. Production of this gas awaits an export pipeline to markets in Canada and the United States. Various industry proposals suggest that a pipeline could be built later in the decade.

Devon also drills for and produces “cold-flow” heavy oil in the Lloydminster area of Alberta and Saskatchewan where oil is found in multiple horizons generally at depths of 1,000 to 2,000 feet. In 2003, Devon drilled 263 wells in the Lloydminster area. Average net daily production from the area is approximately 34 MMcf of natural gas and 13,300 Bbls of crude oil.

Devon also owns a 13% working interest in the ConocoPhillips-operated Surmont thermal heavy oil project. Surmont, located north of Jackfish, is designed to produce up to 100,000 barrels of heavy oil per day by 2012. Surmont will also apply SAGD recovery technology.

International

The Ocean merger more than doubled Devon’s oil and gas reserves outside North America. At December 31, 2003, these international countries accounted for 15% of Devon’s worldwide proved reserves. Most significant was Ocean’s 24% working interest in the Exxon-Mobil-operated Zafiro field, offshore Equatorial Guinea in West Africa. During 2003, production from Zafiro increased significantly due to the addition of the Southern Expansion Area (SEA) in July. Production from the SEA increased total field capacity to 300,000 barrels of oil per day. Devon’s net share increased by about 15,000 barrels to more than 50,000 barrels per day. Devon’s production from Zafiro is expected to decline by about 7,000 barrels per day in the second quarter of 2004. The decline will occur when Devon reaches payout of a portion of its investment in the project and the government’s share of production increases.

Devon experienced another boost in international production in 2003 when its Panyu project offshore China commenced production late in the year. Panyu, in the Pearl River Mouth of the South China Sea, was discovered in 1998. In early 2004, production from the first eight of 27 planned wells reached 50,000 barrels per day. Devon has a 24.5% working interest in the project and expects its share of production to average about 16,000 barrels per day in 2004.

In Azerbaijan in the Caspian Sea, Devon has a 5.6% carried working interest in the Azeri-Chirag-Gunashli, or ACG, oil development project. Devon estimates that the ACG field contains over 4.6 billion barrels of gross proved oil reserves. Oil production from the ACG field will increase dramatically upon completion of the Baku-T’Bilisi-Ceyhan pipeline, which is planned for 2005. Devon’s net share is expected to peak at about 50,000 barrels per day in 2008 or 2009.

Devon also acquired minor producing properties in the Ocean merger in Cote d’Ivoire, Egypt, Indonesia and Russia. Ocean also held exploratory blocks in Angola, Brazil, Equatorial Guinea, Nigeria and Syria. Devon plans to drill exploratory wells in each of the aforementioned countries, except Cote d’Ivoire and Indonesia, in 2004. Devon also produces oil and holds exploratory blocks in Gabon.

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 alleging violation of the federal False Claims Act. The suits allege that the producers and related parties used below-market prices, improper deductions, improper measurement techniques and transactions with affiliates which resulted in underpayment of royalties in connection with natural gas and natural gas liquids produced and sold from federal and Indian owned or controlled lands. The principal suit in which Devon is a defendant is *United States ex rel. Wright v. Chevron USA, Inc. et al.* (the "*Wright* case"). The suit was originally filed in August 1996 in the United States District Court for the Eastern District of Texas, but was consolidated in October 2000 with the other suits for pre-trial proceedings in the United States District Court for the District of Wyoming. On July 10, 2003, the District of Wyoming remanded the *Wright* case back to the Eastern District of Texas to resume proceedings. Devon believes that it has acted reasonably, has legitimate and strong defenses to all allegations in the suit, and has paid royalties in good faith. Devon does not currently believe that it is subject to material exposure in association with this lawsuit and no liability has been recorded in connection therewith.

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

Tax Treatment of Exchangeable Debentures

As described more fully in Note 8 to the consolidated financial statements included in "Item 8. Financial Statements and Supplementary Data" of this report, Devon has certain exchangeable debentures, with a principal amount totaling $760 million, which are exchangeable at the option of the holders into shares of ChevronTexaco common stock owned by Devon. The debentures were assumed, and the ChevronTexaco common stock was acquired, by Devon in the 1999 PennzEnergy merger.

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

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

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

reduce Devon's operating cash flow in the year of payment, it would not affect Devon's net earnings for any period, and the operating cash flow effect would reverse in future years.

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

Other Matters

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

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 2003.

PART II

Item 5. *Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities*

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 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 Stock Exchange		
	High (US$)	Low (US$)	Average Daily Volume	High (CN$)	Low (CN$)	Average Daily Volume
2002:						
Quarter Ended March 31, 2002	49.10	34.40	1,197,478	77.46	54.70	12,353
Quarter Ended June 30, 2002	52.28	45.05	1,005,613	79.54	71.50	2,840
Quarter Ended September 30, 2002	49.70	33.87	1,047,531	76.97	54.55	2,897
Quarter Ended December 31, 2002	53.10	42.14	1,123,356	82.50	67.25	1,222
2003:						
Quarter Ended March 31, 2003	50.37	42.45	1,448,721	75.60	65.00	379
Quarter Ended June 30, 2003	56.65	45.25	1,703,900	74.74	64.96	959
Quarter Ended September 30, 2003	53.48	46.38	1,448,736	74.13	63.73	1,370
Quarter Ended December 31, 2003	58.80	45.90	1,386,548	78.20	61.00	1,534

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. Effective March 31, 2004, Devon increased its quarterly dividend payment to $0.10 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 February 29, 2004, there were 21,341 holders of record of Devon common stock and 578 holders of record for the exchangeable shares.

Item 6. ***Selected Financial Data***

The following selected financial information (not covered by the independent auditors' report) 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." Note 2 to the consolidated financial statements included in Item 8 of this report contains information on mergers and acquisitions which occurred in 2003 and 2002, as well as unaudited pro forma financial data for the years 2003 and 2002. Note 16 to the consolidated financial statements included in Item 8 contains information on operations which were discontinued in 2002.

	Year Ended December 31,				
	2003	2002	2001	2000	1999
	(In millions, except per share data and ratios)				
Operating Results					
Total revenues	$7,352	4,316	2,864	2,587	1,140
Total operating costs and expenses	4,710	3,775	2,672	1,431	1,309
Earnings (loss) from operations	2,642	541	192	1,156	(169)
Net other expenses	397	675	164	118	99
Earnings (loss) from continuing operations before income taxes and cumulative effect of change in accounting principle	2,245	(134)	28	1,038	(268)
Total income tax expense (benefit)	514	(193)	5	377	(75)
Earnings (loss) from continuing operations before cumulative effect of change in accounting principle	1,731	59	23	661	(193)
Net results of discontinued operations	—	45	31	69	39
Earnings (loss) before cumulative effect of change in accounting principle	1,731	104	54	730	(154)
Cumulative effect of change in accounting principle, net of tax	16	—	49	—	—
Net earnings (loss)	$1,747	104	103	730	(154)
Net earnings (loss) applicable to common stockholders	$1,737	94	93	720	(158)
Basic net earnings (loss) per share:					
Earnings (loss) from continuing operations	$ 8.24	0.32	0.09	5.13	(2.13)
Net results of discontinued operations	—	0.29	0.25	0.53	0.45
Cumulative effect of change in accounting principle	0.08	—	0.39	—	—
Net earnings (loss)	$ 8.32	0.61	0.73	5.66	(1.68)
Diluted net earnings (loss) per share:					
Earnings (loss) from continuing operations	$ 8.00	0.32	0.09	4.97	(2.13)
Net results of discontinued operations	—	0.29	0.25	0.53	0.45
Cumulative effect of change in accounting principle	0.07	—	0.38	—	—
Net earnings (loss)	$ 8.07	0.61	0.72	5.50	(1.68)
Cash dividends per common share(1)	$ 0.20	0.20	0.20	0.17	0.14
Weighted average common shares outstanding:					
Basic	209	155	128	127	94
Diluted	217	156	130	132	99

	Year Ended December 31,				
	2003	2002	2001	2000	1999
	(In millions, except per share data and ratios)				
Ratio of earnings to fixed charges(2)	4.87	N/A	1.12	7.34	N/A
Ratio of earnings to combined fixed charges and preferred stock dividends (2)	4.74	N/A	1.05	6.70	N/A
Cash Flow Data					
Net cash provided by operating activities	$ 3,768	1,754	1,910	1,589	539
Net cash used in investing activities	$(2,432)	(2,046)	(5,285)	(1,173)	(768)
Net cash (used in) provided by financing activities	$ (414)	401	3,370	(390)	377
Production, Price and Other Data(3)					
Production:					
Oil (MMBbls)	62	42	36	37	25
Gas (Bcf)	863	761	489	417	295
NGLs (MMBbls)	22	19	8	7	5
MMBoe(4)	228	188	126	113	79
Average prices:					
Oil (Per Bbl)	$ 25.63	21.71	21.41	24.99	17.78
Gas (Per Mcf)	$ 4.51	2.80	3.84	3.53	2.09
NGLs (Per Bbl)	$ 18.65	14.05	16.99	20.87	13.28
Per Boe(4)	$ 25.88	17.61	22.19	22.38	14.22
Costs per Boe(4):					
Production and operating expenses	$ 5.63	4.71	5.29	4.81	4.15
Depreciation, depletion and amortization of oil and gas properties	$ 7.33	5.88	6.30	5.58	4.60

	December 31,				
	2003	2002	2001	2000	1999
	(In millions)				
Balance Sheet Data					
Total assets	$27,162	16,225	13,184	6,860	6,096
Long-term debt	$ 8,580	7,562	6,589	2,049	2,416
Preferred stock of a subsidiary	$ 55	—	—	—	—
Stockholders' equity	$11,056	4,653	3,259	3,277	2,521

(1) Devon acquired another entity via a merger in 2000, which was accounted for using the pooling-of-interests method of accounting for business combinations. This accounting method required Devon to report the results of both companies as if they had always been combined. Therefore, the cash dividends per share presented through 2000 are not representative of the actual amounts paid by Devon on a historical basis. For the years 1999 and 2000, Devon's historical cash dividends per share were $0.20 in each year.

(2) For purposes of calculating the ratio of earnings to fixed charges and 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, dividends on subsidiary's preferred stock, 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 2002 and 1999, earnings were insufficient to cover fixed charges by $135 million and $264 million, respectively.

For the years 2002 and 1999, earnings were insufficient to cover combined fixed charges and preferred stock dividends by $151 million and $270 million, respectively.

(3) The preceding production, price and other data exclude the amounts related to discontinued operations for all periods presented. The preceding price data includes the effect of hedges.

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

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 2001 through 2003. Reference is made to "Item 6. Selected Financial Data" and "Item 8. Financial Statements and Supplementary Data."

Overview

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

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

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

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

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

Additionally, the weakening of the U.S. dollar versus the Canadian dollar caused increases in all of our Canadian dollar expenses as expressed in U.S. dollars. This contributed approximately $88 million in aggregate, or $0.39 per Boe, of increase in 2003 production and operating costs, depreciation, depletion and

amortization expenses and general and administrative expenses. Based on Devon's assumption that the average Canadian-to-U.S. dollar exchange rate will increase from $0.7160 in 2003 to $0.7600 in 2004, the exchange rate effect would increase these expense categories another $58 million, or $0.23 per Boe from 2003 to 2004.

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

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

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

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

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

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

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

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

Results of Operations

Revenues

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

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

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

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

	International				
	Year Ended December 31,				
	2003	2003 vs 2002(2)	2002	2002 vs 2001(2)	2001
Production					
Oil (MMBbls)	17	+662%	2	+0%	2
Gas (Bcf)	7	N/M	—	N/M	—
NGLs (MMBbls)	—	N/M	—	N/M	—
Oil, gas and NGLs (MMBoe)(1)	19	+719%	2	+0%	2
Average Prices					
Oil (per Bbl)	$23.64	+0%	23.70	+1%	23.42
Gas (per Mcf)	$ 3.47	N/M	—	N/M	—
NGLs (per Bbl)	$21.45	N/M	—	N/M	—
Oil, gas and NGLs (per Boe)(1)	$23.45	-1%	23.70	+1%	23.42
Revenues ($ in millions)					
Oil	$ 409	+660%	54	+4%	52
Gas	$ 23	N/M	—	N/M	—
NGLs	$ 4	N/M	—	N/M	—
Oil, gas and NGLs	$ 436	+710%	54	+4%	52

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

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

N/M Not meaningful.

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

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

Oil Revenues

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

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

Gas Revenues

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

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

NGL Revenues

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

2002 vs. 2001 NGL revenues increased $144 million in 2002. An 11 million barrel increase in 2002 production caused revenues to increase $202 million. The Anderson acquisition and Mitchell merger accounted for 12 million barrels of increased production. This was partially offset by production lost from

divestitures. The effects of the net production increase were partially offset by a $2.94 per barrel decrease in the average NGL price in 2002.

Marketing and Midstream Revenues

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

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

Operating Costs and Expenses

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

	Year Ended December 31,				
	2003	2003 vs 2002(2)	2002	2002 vs 2001(2)	2001
Operating Costs and Expenses ($ in millions):					
Production and operating expenses:					
Lease operating expenses	$ 871	+40%	621	+33%	467
Transportation costs	207	+34%	154	+86%	83
Production taxes	204	+84%	111	-4%	116
Total production and operating expenses	1,282	+45%	886	+33%	666
Depreciation, depletion and amortization of oil and gas properties	1,668	+51%	1,106	+39%	793
Accretion of asset retirement obligation	36	N/M	—	N/M	—
Amortization of goodwill	—	N/M	—	-100%	34
Subtotal	2,986	+50%	1,992	+33%	1,493
Marketing and midstream operating costs and expenses	1,174	+45%	808	+1,619%	47
Depreciation and amortization of non-oil and gas properties	125	+19%	105	+176%	38
General and administrative expenses	307	+40%	219	+92%	114
Expenses related to mergers	7	N/M	—	-100%	1
Reduction of carrying value of oil and gas properties	111	-83%	651	-34%	979
Total	$4,710	+25%	3,775	+41%	2,672
Operating Costs and Expenses per Boe:					
Production and operating expenses:					
Lease operating expenses	$ 3.82	+16%	3.30	-11%	3.71
Transportation costs	0.91	+11%	0.82	+24%	0.66
Production taxes	0.90	+53%	0.59	-36%	0.92
Total production and operating expenses	5.63	+20%	4.71	-11%	5.29
Depreciation, depletion and amortization of oil and gas properties	7.33	+25%	5.88	-7%	6.30
Accretion of asset retirement obligation	0.16	N/M	—	N/M	—
Amortization of goodwill	—	N/M	—	-100%	0.27
Subtotal	13.12	+24%	10.59	-11%	11.86
Marketing and midstream operating costs and expenses(1)	5.15	+20%	4.29	+1,059%	0.37
Depreciation and amortization of non-oil and gas properties(1)	0.55	+0%	0.55	+83%	0.30
General and administrative expenses(1)	1.35	+16%	1.16	+27%	0.91
Expenses related to mergers(1)	0.03	N/M	—	-100%	0.01
Reduction of carrying value of oil and gas properties(1)	0.49	-86%	3.45	-56%	7.78
Total	$20.69	+3%	20.04	-6%	21.23

(1) Though per Boe amounts for these expense items may be helpful for profitability trend analysis, these expenses are not directly attributable to production volumes.

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

N/M Not meaningful.

Oil, Gas and NGLs Production and Operating Expenses

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

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

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

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

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

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

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

Depreciation, Depletion and Amortization of Oil and Gas Properties ("DD&A")

DD&A of oil and gas properties is calculated as the percentage of total proved reserve volumes produced during the year, multiplied by the net capitalized investment plus future development costs in those reserves (the "depletable base"). Generally, if reserve volumes are revised up or down, then the DD&A rate per unit of production will change inversely. However, if the depletable base changes, then the DD&A rate moves in the same direction. The per unit DD&A rate is not affected by production volumes. Absolute or total DD&A, as opposed to the rate per unit of production, generally moves in the same direction as production volumes. Oil and gas property DD&A is calculated separately on a country-by-country basis.

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

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

Accretion of Asset Retirement Obligation

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

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

Marketing and Midstream Operating Costs and Expenses

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

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

General and Administrative Expenses (“G&A”)

Devon’s net G&A consists of three primary components. The largest of these components is the gross amount of expenses incurred for personnel costs, office expenses, professional fees and other G&A items. The gross amount of these expenses is partially reduced by two offsetting components. One is the amount of G&A capitalized pursuant to the full cost method of accounting. The other is the amount of G&A reimbursed by working interest owners of properties for which Devon serves as the operator. These reimbursements are received during both the drilling and operational stages of a property’s life. The gross amount of G&A incurred, less the amounts capitalized and reimbursed, is recorded as net G&A in the consolidated statements of operations. Net G&A includes expenses related to oil, gas and NGL exploration

and production activities, as well as marketing and midstream activities. See the following table for a summary of G&A expenses by component.

	Year Ended December 31,				
	2003	2003 vs 2002	2002	2002 vs 2001	2001
	($ in millions)				
Gross G&A	$ 524	+35%	387	+56%	248
Capitalized G&A	(140)	+44%	(97)	+26%	(77)
Reimbursed G&A	(77)	+ 9%	(71)	+25%	(57)
Net G&A	$ 307	+40%	219	+92%	114

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

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

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

Reduction of Carrying Value of Oil and Gas Properties

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

If, subsequent to the end of the quarter but prior to the applicable financial statements being published, prices increase to levels such that the ceiling would exceed the costs to be recovered, a writedown otherwise indicated at the end of the quarter is not required to be recorded. A writedown indicated at the end of a quarter is also not required if the value of additional reserves proved up on properties after the end of the quarter but prior to the publishing of the financial statements would result in the ceiling exceeding the costs to be recovered, as long as the properties were owned at the end of the quarter.

Under the purchase method of accounting for business combinations, acquired oil and gas properties are recorded at estimated fair value as of the date of purchase. Devon estimates such fair value using its estimates of future oil, gas and NGL prices. In contrast, the ceiling calculation dictates that prices in

effect as of the last day of the applicable quarter are held constant indefinitely. Accordingly, the resulting value from the ceiling calculation is not necessarily indicative of the fair value of the reserves.

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

	Year Ended December 31,					
	2003		2002		2001	
	Gross	Net of Taxes	Gross	Net of Taxes	Gross	Net of Taxes
	(In millions)					
United States	$ —	—	—	—	449	281
Canada	—	—	651	371	434	252
International	68	36	—	—	—	—
Total	$ 68	36	651	371	883	533

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

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

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

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

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

on a NYMEX oil price of $19.84 per barrel, a Henry Hub gas price of $2.65 per MMBtu and an AECO gas price of C$3.67 per MMBtu.

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

Other Income (Expenses)

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

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

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

Interest Expense

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

2002 vs. 2001 Interest expense increased $313 million in 2002. An increase in the average debt balance outstanding from $3.0 billion in 2001 to $8.3 billion in 2002 caused interest expense to increase

$319 million. The increase in average debt outstanding was attributable primarily to the long-term debt issued and assumed as a result of the Mitchell merger and Anderson acquisition.

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

Effects of Changes in Foreign Currency Exchange Rates

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

Impairment of ChevronTexaco Corporation Common Stock in 2002

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

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

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

Beginning in July 2002, the market value of ChevronTexaco common stock began a significant decline. The price per share decreased from $88.50 at June 30, 2002, to $69.25 per share at September 30, 2002, and to $66.48 per share at December 31, 2002. The year-end price of $66.48 represented a 25% decline since June 30, 2002, and a 30% decline from the original valuation in August 1999. As a result of the decline in value during the fourth quarter of 2002, Devon determined that the decline was other than

temporary, as that term is defined by accounting rules. Therefore, the $205 million cumulative decrease in the value of the ChevronTexaco common shares from the initial acquisition in August 1999 to December 31, 2002, was recorded as a noncash charge to Devon's results of operations in the fourth quarter of 2002. Net of the applicable tax benefit, the charge reduced net earnings by $128 million.

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

Income Taxes

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

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

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

Results of Discontinued Operations

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

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

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

	Year Ended December 31,	
	2002	2001
	(In millions)	
Net gain on sale of discontinued operations	$ 31	—
Earnings from discontinued operations before income taxes	23	56
Income tax expense	9	25
Net results of discontinued operations	$ 45	31

Cumulative Effect of Change in Accounting Principle

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

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

Capital Expenditures, Capital Resources and Liquidity

The following discussion of capital expenditures, capital resources and liquidity should be read in conjunction with the consolidated financial statements included in "Item 8. Financial Statements and Supplementary Data".

Capital Expenditures

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

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

Capital Resources and Liquidity

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

Operating Cash Flow

Operating cash flow continued to be a primary source of capital and liquidity in 2003. Operating cash flow in 2003 was $3.8 billion, compared to $1.8 billion in 2002 and $1.9 billion in 2001. The increase in

operating cash flow in 2003 was primarily caused by the increase in revenues, partially offset by increased expenses, as discussed earlier in this section.

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

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

	Price Collars	Price Swap Contracts	Fixed-Price Physical Delivery Contracts	Total
Oil production (MMBbls)				
2004	28	23	—	51
2005	18	8	—	26
Natural gas production (Bcf)				
2004	437	3	16	456
2005	35	3	14	52

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

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

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

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

Credit Lines

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

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

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

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

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

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

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

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

Ocean Debt

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

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

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

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

Debt Ratings

Devon receives debt ratings from the major ratings agencies in the United States. In determining Devon's debt rating, the agencies consider a number of items including, but not limited to, debt levels, planned asset sales, near-term and long-term production growth opportunities, capital allocation challenges, liquidity, asset quality, cost structure, reserve mix, and commodity pricing levels.

Devon's current debt ratings are BBB with a stable outlook by Standard & Poor's, Baa2 with a negative outlook by Moody's and BBB with a stable outlook by Fitch. There are no "rating triggers" in any of Devon's contractual obligations that would accelerate scheduled maturities should Devon's debt rating fall below a specified level. Certain of Devon's agreements related to its oil and natural gas hedges do contain provisions that could require Devon to provide cash collateral in situations where 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 threshold level in circumstances where the market prices for oil or natural gas were rising. It is

unlikely that Devon's debt rating would be subjected to downgrades to non-investment grade levels during such a period of rising oil and natural gas prices.

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

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

Contractual Obligations

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

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

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

Devon assumed two offshore platform spar leases through the 2003 Ocean merger. The spars are being used in the development of the Nansen and Boomvang fields in the Gulf of Mexico. The operating leases are for 20-year terms and contain various options whereby Devon may purchase the lessors' interests in the spars. Devon has guaranteed that the spars will have residual values at the end of the operating leases equal to at least 10% of the fair value of the spars at the inception of the leases. The total guaranteed value is $20 million in 2022. However, such amount may be reduced under the terms of the lease agreements.

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

The above table does not include $200 million of letters of credit that have been issued by commercial banks on Devon's behalf which, if funded, would become borrowings under Devon's revolving

credit facility. Most of these letters of credit have been granted by Devon's financial institutions to support Devon's international and Canadian drilling commitments. The $8.9 billion of long-term debt shown in the table excludes $1 million of net discounts and a $27 million fair value adjustment, both of which are included in the December 31, 2003, book balance of the debt.

Pension Funding and Obligations

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

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

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

The calculation of pension expense and pension liability requires the use of a number of assumptions. Changes in these assumptions can result in different expense and liability amounts, and future actual experience can differ from the assumptions. Devon believes that the two most critical assumptions affecting pension expense and liabilities are the expected long-term rate of return on plan assets and the assumed discount rate.

Devon assumed that its plan assets would generate a long-term weighted average rate of return of 8.25% and 8.27% at December 31, 2003 and 2002, respectively. Devon developed these expected long-term rate of return assumptions by evaluating input from external consultants and economists as well as long-term inflation assumptions. The expected long-term rate of return on plan assets is based on a target allocation of investment types in such assets. The target investment allocation for Devon's plan assets is 50% U.S. large cap equity securities; 15% U.S. small cap equity securities, equally allocated between growth and value; 15% international equity securities, equally allocated between growth and value; and 20% debt securities.

Devon believes that its long-term asset allocation on average will approximate the targeted allocation. Devon regularly reviews its actual asset allocation and periodically rebalances the investments to the targeted allocation when considered appropriate.

Pension expense increases as the expected rate of return on plan assets decreases. A decrease in Devon's long-term rate of return assumption of 100 basis points (from 8.25% to 7.25%) would increase the expected 2004 pension expense by approximately $4 million.

Devon discounted its future pension obligations using a weighted average rate of 6.23% at December 31, 2003, compared to 6.72% at December 31, 2002. The discount rate is determined at the end of each year based on the rate at which obligations could be effectively settled. This rate is based on high-

quality bond yields, after allowing for call and default risk. Devon considers high quality corporate bond yield indices, such as Moody's Aa, when selecting the discount rate.

The pension liability and future pension expense both increase as the discount rate is reduced. Lowering the discount rate by 25 basis points (from 6.23% to 5.98%) would increase Devon's pension liability at December 31, 2003, by approximately $16 million, and increase its estimated 2004 pension expense by approximately $2 million.

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

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

Other Cash Uses

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

During 2001, 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.

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. See Note 18 of the accompanying consolidated financial statements.

The passage of time provides more qualitative information regarding estimates of reserves, and revisions are made to prior estimates to reflect updated information. In the past four years, Devon's annual revisions to its reserve estimates have averaged approximately 2% of the previous year's estimate. However, there can be no assurance that more significant revisions will not be necessary in the future. If future significant revisions are necessary that reduce previously estimated reserve quantities, it could result in a full cost property writedown. In addition to the impact of the estimates of proved reserves on the calculation of the ceiling, estimates of proved reserves are also a significant component of the calculation of DD&A.

While the quantities of proved reserves require substantial judgment, the associated prices of oil, natural gas and NGL reserves, and the applicable discount rate, that are used to calculate the discounted present value of the reserves do not require judgment. The ceiling calculation dictates that prices and costs in effect as of the last day of the period are generally held constant indefinitely. Therefore, the future net revenues associated with the estimated proved reserves are not based on Devon's assessment of future prices or costs, 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 adjusts the end-of-period price by the effect of cash flow hedges in place.

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

Because the ceiling calculation dictates that prices in effect as of the last day of the applicable quarter are held constant indefinitely, and requires a 10% discount factor, the resulting value is not indicative of the true fair value of the reserves. Oil and natural gas prices have historically been cyclical and, on any particular day at the end of a quarter, can be either substantially higher or lower than Devon's long-term price forecast that is a barometer for true fair value. 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.

Derivative Instruments

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

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

The estimates of the fair values of Devon's commodity derivative contracts require substantial judgment. For these contracts, Devon obtains forward price and volatility data for all major oil and gas trading points in North America from independent third parties. These forward prices are compared to the price parameters contained in the hedge agreements, and the resulting estimated future cash inflows or outflows over the lives of the hedge contracts are discounted using Devon's current borrowing rates under its revolving credit facilities. In addition, Devon estimates the option value of price floors and price caps using the Black-Scholes option pricing model. These pricing and discounting variables are sensitive to market volatility as well as changes in forward prices, regional price differentials and interest rates. Fair

values of Devon's other derivative contracts require less judgment to estimate and are primarily based on quotes from independent third parties such as counterparties or brokers.

Business Combinations

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

Under the purchase method, the acquiring company adds to its balance sheet the estimated fair values of the acquired company's assets and liabilities. Any excess of the purchase price over the fair values of the tangible and intangible net assets acquired is recorded as goodwill. Goodwill is assessed for impairment at least annually.

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

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

Devon estimates future prices to apply to the estimated reserve quantities acquired, and estimates future operating and development costs, to arrive at estimates of future net revenues. For estimated proved reserves, the future net revenues are then discounted using a rate determined appropriate at the time of the business combination based upon Devon's cost of capital.

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

Except for the 2002 Mitchell merger, Devon's mergers and acquisitions have involved other entities whose operations were predominantly in the area of exploration, development and production activities

related to oil and gas properties. However, in addition to exploration, development and production activities, Mitchell's business also included substantial marketing and midstream activities. Therefore, a portion of the Mitchell purchase price was allocated to the fair value of Mitchell's marketing and midstream facilities and equipment, which consisted primarily of natural gas processing plants and natural gas pipeline systems.

Because the Mitchell midstream assets primarily served gas producing properties that were also acquired by Devon from Mitchell, certain of the assumptions regarding future operations of the gas producing properties were also integral to the value of the midstream assets. For example, future quantities of natural gas estimated to be processed by natural gas processing plants were based on the same estimates used to value the proved and unproved gas producing properties. Future expected prices for marketing and midstream product sales were also based on price cases consistent with those used to value the oil and gas producing assets acquired from Mitchell. Based on historical costs and known trends and commitments, Devon also estimated future operating and capital costs of the marketing and midstream assets to arrive at estimated future cash flows. These cash flows were discounted at rates consistent with those used to discount future net cash flows from oil and gas producing assets to arrive at Devon's estimated fair value of the marketing and midstream facilities and equipment.

In addition to the valuation methods described above, Devon performs other quantitative analyses to support the indicated value in any business combination. These analyses include information related to comparable companies, comparable transactions and premiums paid.

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

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

In a premiums paid analysis, Devon uses a sample of selected independent exploration and production company transactions in addition to selected transactions of all publicly traded companies announced recently, to review the premiums paid to the price of the target one day, one week and one month prior to the announcement of the transaction. Devon uses this information to determine the mean and median premiums paid and compares them to the proposed business combination premium for reasonableness.

Valuation of Goodwill

Goodwill and intangible assets with indefinite useful lives are tested for impairment at least annually. This requires Devon to estimate the fair values of its own assets and liabilities in a manner similar to the process described above for a business combination. Therefore, considerable judgment similar to that described above in connection with estimating the fair value of an acquired company in a business combination is also required to assess goodwill for impairment on an annual basis.

Drilling and Mineral Rights

In 2003, the Securities Exchange Commission ("SEC") inquired of the Financial Accounting Standards Board regarding the application of certain provisions of SFAS No. 141, *Business Combinations*, ("SFAS No. 141") and SFAS No. 142, *Goodwill and Other Intangible Assets*, ("SFAS No. 142") to oil and gas companies. SFAS Nos. 141 and 142 became effective for transactions subsequent to June 30, 2001. SFAS No. 141 requires that all business combinations initiated after June 30, 2001 be accounted for using the purchase method and that acquired intangible assets be disaggregated and reported separately

from goodwill. Specifically, the SEC's inquiry is based on whether costs of contract-based drilling and mineral use rights ("mineral rights") should be recorded and disclosed as intangible assets under the guidance in SFAS Nos. 141 and 142. The current practice for Devon and the industry is to present oil and gas related assets, including mineral rights, as property and equipment (tangible assets) on the balance sheet. Since June 30, 2001, Devon has entered into business combinations with Anderson, Mitchell, and Ocean with an aggregate accounting purchase price of $18.2 billion. The majority of the purchase price has been allocated to oil and gas property.

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

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

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

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

Impact of Recently Issued Accounting Standards Not Yet Adopted

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

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

2004 Estimates

The forward-looking statements provided in this discussion are based on management’s examination of historical operating trends, the information which was used to prepare the December 31, 2003 reserve reports and other data in Devon’s possession or available from third parties. Devon cautions that its future oil, natural gas and NGL production, revenues and expenses are subject to all of the risks and uncertainties normally incident to the exploration for and development, production and sale of oil, gas and NGLs. These risks include, but are not limited to, price volatility, inflation or lack of availability of goods and services, environmental risks, drilling risks, regulatory changes, the uncertainty inherent in estimating future oil and gas production or reserves, and other risks as outlined below.

Additionally, Devon cautions that its future marketing and midstream revenues and expenses are subject to all of the risks and uncertainties normally incident to the marketing and midstream business. These risks include, but are not limited to, price volatility, environmental risks, regulatory changes, the uncertainty inherent in estimating future processing volumes and pipeline throughput, cost of goods and services and other risks as outlined below.

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

Specific Assumptions and Risks Related to Price and Production Estimates

Prices for oil, natural gas and NGLs are determined primarily by prevailing market conditions. Market conditions for these products are influenced by regional and worldwide economic conditions, weather and other local market conditions. These factors are beyond Devon’s control and are difficult to predict. In addition to volatility in general, Devon’s oil, gas and NGL prices may vary considerably due to differences between regional markets, transportation availability and costs and demand for the various products derived from oil, natural gas and NGLs. Substantially all of Devon’s revenues are attributable to sales, processing and transportation of these three commodities. Consequently, Devon’s financial results and resources are highly influenced by price volatility.

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

Estimates for Devon’s future processing and transport of oil, natural gas and NGLs are based on the assumption that market demand and prices for oil, gas and NGLs will continue at levels that allow for profitable processing and transport of these products. There can be no assurance of such stability.

The production, transportation, processing and marketing of oil, natural gas and NGLs are complex processes which are subject to disruption due to transportation and processing availability, mechanical failure, human error, meteorological events including, but not limited to, hurricanes, and numerous other

factors. The following forward-looking statements were prepared assuming demand, curtailment, producibility and general market conditions for Devon's oil, natural gas and NGLs during 2004 will be substantially similar to those of 2003, unless otherwise noted.

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

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

Geographic Reporting Areas for 2004

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

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

Year 2004 Potential Operating Items

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

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

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

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

	Bbls/Day	Price/Bbl	Months of Production
United States Onshore	11,000	$27.51	Jan - Dec
United States Offshore	18,000	$27.16	Jan - Dec
Canada	15,000	$27.53	Jan - Dec
International	20,000	$26.03	Jan - Dec

Oil Prices — Floating Devon's 2004 average prices for each of its areas are expected to differ from the NYMEX price as set forth in the following table. The NYMEX price is the monthly average of settled prices on each trading day for West Texas Intermediate crude oil delivered at Cushing, Oklahoma.

	Expected Range of Oil Prices Less than NYMEX Price
United States Onshore	($3.00) to ($2.00)
United States Offshore	($4.50) to ($2.50)
Canada	($6.50) to ($4.50)
International	($5.50) to ($3.00)

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

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

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

		Weighted Average		
Area (Range of Floor Prices/ Ceiling Prices)	Bbls/Day	Floor Price Per Bbl	Ceiling Price Per Bbl	Months of Production
United States Onshore				
($20.00 - $21.50/ $26.50 - $27.90)	3,000	$20.83	$27.43	Jan - Dec
($20.00 - $22.00/ $28.35 - $29.75)	6,000	$21.42	$29.25	Jan - Dec
($22.00 - $22.00/ $30.10 - $30.60)	2,000	$22.00	$30.35	Jan - Dec
United States Offshore				
($20.00 - $22.00/ $27.55 - $29.75)	6,000	$21.42	$28.75	Jan - Dec
($22.00 - $22.00/ $30.00 - $31.40)	7,000	$22.00	$30.74	Jan - Dec
Canada				
($20.00 - $21.50/ $26.50 - $27.70)	3,000	$20.50	$27.07	Jan - Dec
($20.00 - $22.00/ $28.00 - $29.20)	5,000	$21.10	$28.69	Jan - Dec
($22.00 - $22.00/ $29.80 - $32.35)	8,000	$22.00	$31.14	Jan - Dec
International				
($22.31 - $22.31/ $30.11 - $31.51)	27,000	$22.31	$30.82	Jan - Dec
($22.31 - $22.31/ $31.56 - $32.81)	10,000	$22.31	$31.96	Jan - Dec

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

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

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

	Mcf/Day	Price/Mcf	Months of Production
United States Onshore	8,435	$3.10	Jan - Dec
Canada	43,578	$2.76	Jan - Jun
Canada	41,920	$2.79	Jul - Dec

Gas Prices — Floating For the natural gas production for which prices have not been fixed, Devon's 2004 average prices for each of its areas are expected to differ from the NYMEX price as set forth in the following table. The NYMEX price is determined to be the first-of-month South Louisiana Henry Hub price index as published monthly in *Inside FERC.*

	Expected Range of Oil Prices Less than NYMEX Price
United States Onshore	($0.80) to ($0.30)
United States Offshore	($0.25) to ($0.05)
Canada	($1.10) to ($0.60)
International	($3.00) to ($2.00)

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

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

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

Area (Range Of Floor Prices/ Ceiling Prices)	MMBtu/ Day	Weighted Average Floor Price per MMBtu	Weighted Average Ceiling Price per MMBtu	Months of Production
United States Onshore				
($3.32 - $4.22/$4.97 - $6.37)	110,000	$3.77	$ 5.91	Jan - Dec
($3.32 - $4.47/$6.47 - $7.35)	215,000	$4.10	$ 6.87	Jan - Dec
($3.32 - $4.00/$7.45 - $7.85)	45,000	$3.54	$ 7.62	Jan - Dec
($3.50 - $4.07/$8.02 - $8.86)	100,000	$3.61	$ 8.37	Jan - Dec
($4.00 - $4.15/$7.00 - $7.00)	40,000	$4.06	$ 7.00	Jan - Jun
($4.02 - $4.03/$6.98 - $6.99)	50,000	$4.03	$ 6.99	Jul - Dec
United States Offshore				
($3.25 - $3.25/$7.00 - $7.00)	10,000	$3.25	$ 7.00	Jan - Dec
($3.50 - $3.50/$7.40 - $7.90)	50,000	$3.50	$ 7.74	Jan - Dec
($4.00 - $4.00/$7.43 - $8.80)	130,000	$4.00	$ 7.71	Jan - Dec
($4.00 - $4.12/$7.00 - $7.00)	60,000	$4.07	$ 7.00	Jan - Jun
($4.00 - $4.00/$7.00 - $7.00)	50,000	$4.00	$ 7.00	Jul - Dec
Canada				
($4.10 - $4.21/$6.46 - $7.07)	60,000	$4.18	$ 6.76	Jan - Dec
($4.06 - $4.59/$7.17 - $7.94)	140,000	$4.29	$ 7.51	Jan - Dec
($3.98 - $4.13/$8.43 - $8.75)	60,000	$4.04	$ 8.63	Jan - Dec
($3.96 - $4.25/$9.14 - $9.64)	70,000	$4.06	$ 9.33	Jan - Dec
($3.96 - $4.05/$9.91 - $10.54)	25,000	$4.02	$10.37	Jan - Dec
($4.60 - $4.85/$6.53 - $6.53)	90,000	$4.75	$ 6.53	Jan - Jun
($4.60 - $4.86/$6.53 - $6.71)	70,000	$4.73	$ 6.61	Jul - Dec

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

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

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

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

These factors, coupled with uncertainty of future natural gas and NGL prices, increase the uncertainty inherent in estimating future marketing and midstream revenues and expenses. Given these uncertainties, Devon estimates that 2004 marketing and midstream revenues will be between $1.07 billion and $1.14 billion, and marketing and midstream expenses will be between $860 million and $910 million.

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

Given these uncertainties, Devon estimates that 2004 lease operating expenses will be between $1.05 billion and $1.12 billion, transportation costs will be between $220 million and $230 million, and production taxes will be between 3.1% and 3.6% of consolidated oil, natural gas and NGL revenues, excluding revenues related to hedges upon which production taxes are not incurred.

Depreciation, Depletion and Amortization ("DD&A") The 2004 oil and gas property DD&A rate will depend on various factors. Most notable among such factors are the amount of proved reserves that will be added from drilling or acquisition efforts in 2004 compared to the costs incurred for such efforts, and the revisions to Devon's year-end 2003 reserve estimates that, based on prior experience, are likely to be made during 2004.

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

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

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

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

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

Because the ceiling calculation dictates that prices in effect as of the last day of the applicable quarter are held constant indefinitely, and requires a 10% discount factor, the resulting value is not indicative of the true fair value of the reserves. Oil and natural gas prices have historically been cyclical and, on any particular day at the end of a quarter, can be either substantially higher or lower than Devon's long-term price forecast that is a barometer for true fair value. 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.

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.

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

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

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

Debt Instrument	Face Value	Floating Rate
5-year term loan facility due in 2006	$635	LIBOR plus 100 basis points
4.375% senior notes due in 2007	$400	LIBOR plus 40 basis points
10.25% bond due in 2005	$236	LIBOR plus 711 basis points
8.05% senior notes due in 2004	$125	LIBOR plus 336 basis points
2.75% notes due in 2006	$500	LIBOR less 26.8 basis points
7.625% senior notes due in 2005	$125	LIBOR plus 237 basis points

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

Devon's interest expense totals have historically included payments of facility and agency fees, amortization of debt issuance costs, the effect of interest rate swaps not accounted for as hedges, and other miscellaneous items not related to the debt balances outstanding. Devon expects between $15 million and

$20 million of such items to be included in its 2004 interest expense. Also, Devon expects to capitalize between $25 million and $30 million of interest during 2004.

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

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

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

Income Taxes Devon's financial income tax rate in 2004 will vary materially depending on the actual amount of financial pre-tax earnings. The tax rate for 2004 will be significantly affected by the proportional share of consolidated pre-tax earnings generated by U.S., Canadian and International operations due to the different tax rates of each country. There are certain tax deductions and credits that will have a fixed impact on 2004's income tax expense regardless of the level of pre-tax earnings that are produced. Given the uncertainty of its pre-tax earnings amount, Devon estimates that its consolidated financial income tax rate in 2004 will be between 25% and 45%. The current income tax rate is expected to be between 20% and 30%. The deferred income tax rate is expected to be between 5% and 15%. Significant changes in estimated capital expenditures, production levels of oil, gas and NGLs, the prices of such products, marketing and midstream revenues, or any of the various expense items could materially alter the effect of the aforementioned tax deductions and credits on 2004's financial income tax rates.

Year 2004 Potential Capital Sources, Uses and Liquidity

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

Devon's capital expenditures budget is based on an expected range of future oil, natural gas and NGL prices as well as the expected costs of the capital additions. Should actual prices received differ materially from Devon's price expectations for its future production, some projects may be accelerated or deferred and, consequently, may increase or decrease total 2004 capital expenditures. In addition, if the actual material or labor costs of the budgeted items vary significantly from the anticipated amounts, actual capital expenditures could vary materially from Devon's estimates.

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

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

	United States Onshore	United States Offshore	Canada	International	Total
			(In millions)		
Related to Proved Reserves	$270 - $280	$130 - $140	$ 40 - $ 50	$ 70 - $ 80	$ 510 - $ 550
Lower Risk/Reward Projects	$405 - $560	$ 95 - $110	$400 - $500	$ 50 - $ 60	$ 950 - $1,230
Higher Risk/Reward Projects	$ 95 - $105	$235 - $255	$250 - $280	$100 - $120	$ 680 - $ 760
Total	$770 - $945	$460 - $505	$690 - $830	$220 - $260	$2,140 - $2,540

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

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

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

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

Commodity Price Risk

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

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

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

Price Swaps

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

Oil Production

	2004		
Area	Bbls/Day	Price/ Bbl	Months of Production
United States Onshore	11,000	$27.51	Jan - Dec
United States Offshore	18,000	$27.16	Jan - Dec
Canada	15,000	$27.53	Jan - Dec
International	20,000	$26.03	Jan - Dec

	2005		
Area	Bbls/Day	Price/ Bbl	Months of Production
United States Offshore	10,000	$27.17	Jan - Dec
Canada	6,000	$27.26	Jan - Dec
International	6,000	$25.88	Jan - Dec

Gas Production

	2004		
Area	Mcf/Day	Price/ Mcf	Months of Production
United States Onshore	8,435	$3.10	Jan - Dec

	2005		
Area	Mcf/Day	Price/ Mcf	Months of Production
United States Onshore	7,343	$2.97	Jan - Dec

Costless Price Collars

Devon has also entered into costless price collars that set a floor and ceiling price for a portion of its 2004 and 2005 oil production that otherwise are subject to floating prices. The floor and ceiling prices

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

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

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

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

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

Oil Production

	2004			
		Weighted Average		
Area (Range of Floor Prices/Ceiling Prices)	Bbls/Day	Floor Price PerBbl	Ceiling Price Per Bbl	Months of Production
United States Onshore				
($20.00 - $21.50/ $26.50 - $27.90)	3,000	$20.83	$27.43	Jan - Dec
($20.00 - $22.00/ $28.35 - $29.75)	6,000	$21.42	$29.25	Jan - Dec
($22.00 - $22.00/ $30.10 - $30.60)	2,000	$22.00	$30.35	Jan - Dec
United States Offshore				
($20.00 - $22.00/ $27.55 - $29.75)	6,000	$21.42	$28.75	Jan - Dec
($22.00 - $22.00/ $30.00 - $31.40)	7,000	$22.00	$30.74	Jan - Dec
Canada				
($20.00 - $21.50/ $26.50 - $27.70)	3,000	$20.50	$27.07	Jan - Dec
($20.00 - $22.00/ $28.00 - $29.20)	5,000	$21.10	$28.69	Jan - Dec
($22.00 - $22.00/ $29.80 - $32.35)	8,000	$22.00	$31.14	Jan - Dec
International				
($22.31 - $22.31/ $30.11 - $31.51)	27,000	$22.31	$30.82	Jan - Dec
($22.31 - $22.31/ $31.56 - $32.81)	10,000	$22.31	$31.96	Jan - Dec

Area (Range of Floor Prices/Ceiling Prices)	2005 Bbls/Day	Weighted Average Floor Price Per Bbl	Weighted Average Ceiling Price Per Bbl	Months of Production
United States Onshore ($22.00 - $22.00/ $28.00 - $28.75)	3,000	$22.00	$28.25	Jan - Dec
United States Offshore ($22.00 - $22.00/ $27.50 - $29.00)	17,000	$22.00	$27.62	Jan - Dec
Canada ($22.00 - $22.00/ $27.50 - $29.10)	15,000	$22.00	$28.28	Jan - Dec
International ($22.75 - $22.75/ $28.45 - $29.25)	15,000	$22.75	$28.86	Jan - Dec

Gas Production

Area (Range of Floor Prices/Ceiling Prices)	2004 MMBtu/Day	Weighted Average Floor Price Per MMBtu	Weighted Average Ceiling Price Per MMBtu	Months of Production
United States Onshore				
($3.32 - $4.22/$4.97 - $6.37)	110,000	$3.77	$ 5.91	Jan - Dec
($3.32 - $4.47/$6.47 - $7.35)	215,000	$4.10	$ 6.87	Jan - Dec
($3.32 - $4.00/$7.45 - $7.85)	45,000	$3.54	$ 7.62	Jan - Dec
($3.50 - $4.07/$8.02 - $8.86)	100,000	$3.61	$ 8.37	Jan - Dec
($4.00 - $4.15/$7.00 - $7.00)	40,000	$4.06	$ 7.00	Jan - Jun
($4.02 - $4.03/$6.98 - $6.99)	50,000	$4.03	$ 6.99	Jul - Dec
United States Offshore				
($3.25 - $3.25/$7.00 - $7.00)	10,000	$3.25	$ 7.00	Jan - Dec
($3.50 - $3.50/$7.40 - $7.90)	50,000	$3.50	$ 7.74	Jan - Dec
($4.00 - $4.00/$7.43 - $8.80)	130,000	$4.00	$ 7.71	Jan - Dec
($4.00 - $4.12/$7.00 - $7.00)	60,000	$4.07	$ 7.00	Jan - Jun
($4.00 - $4.00/$7.00 - $7.00)	50,000	$4.00	$ 7.00	Jul - Dec
Canada				
($4.10 - $4.21/$6.46 - $7.07)	60,000	$4.18	$ 6.76	Jan - Dec
($4.06 - $4.59/$7.17 - $7.94)	140,000	$4.29	$ 7.51	Jan - Dec
($3.98 - $4.13/$8.43 - $8.75)	60,000	$4.04	$ 8.63	Jan - Dec
($3.96 - $4.25/$9.14 - $9.64)	70,000	$4.06	$ 9.33	Jan - Dec
($3.96 - $4.05/$9.91 - $10.54)	25,000	$4.02	$10.37	Jan - Dec
($4.60 - $4.85/$6.53 - $6.53)	90,000	$4.75	$ 6.53	Jan - Jun
($4.60 - $4.86/$6.53 - $6.71)	70,000	$4.73	$ 6.61	Jul - Dec

Area (Range of Floor Prices/Ceiling Prices)	2005 MMBtu/Day	Weighted Average Floor Price Per MMBtu	Weighted Average Ceiling Price Per MMBtu	Months of Production
United States Onshore				
($3.97 - $4.05/$6.94 - $6.99)	40,000	$4.01	$6.97	Jan - Jun
United States Offshore				
($3.50 - $3.50/$7.50 - $7.50)	40,000	$3.50	$7.50	Jan - Dec
($4.04 - $4.17/$7.00 - $7.00)	70,000	$4.09	$7.00	Jan - Jun

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

Fixed-Price Physical Delivery Contracts

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

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

Interest Rate Risk

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

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

Debt Instrument	Notional Amount	Floating Rate
4.375% senior notes due in 2007	$400	LIBOR plus 40 basis points
10.25% bond due in 2005	$235	LIBOR plus 711 basis points
8.05% senior notes due in 2004	$125	LIBOR plus 336 basis points
2.75% notes due in 2006	$500	LIBOR less 26.8 basis points
7.625% senior notes due in 2005	$125	LIBOR plus 237 basis points

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

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

Foreign Currency Risk

Devon's net assets, net earnings and cash flows from its Canadian subsidiaries are based on the U.S. dollar equivalent of such amounts measured in the Canadian dollar functional currency. Assets and liabilities of the Canadian subsidiaries are translated to U.S. dollars using the applicable exchange rate as of the end of a reporting period. Revenues, expenses and cash flow are translated using the average exchange rate during the reporting period.

Devon's Canadian subsidiary, Devon Canada, has $400 million of fixed-rate long-term debt that is denominated in U.S. dollars. Changes in the currency conversion rate between the Canadian and

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

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 as of December 31, 2003 and 2002 and the related consolidated statements of operations, stockholders' equity and comprehensive income (loss) and cash flows for each of the years in the three year period ended December 31, 2003. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Devon Energy Corporation and subsidiaries as of December 31, 2003 and 2002, and the results of their operations and their cash flows for each of the years in the three year period ended December 31, 2003 in conformity with accounting principles generally accepted in the United States of America.

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

KPMG LLP

Oklahoma City, Oklahoma
February 4, 2004

DEVON ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31, 2003	December 31, 2002
	(In millions, except share data)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,273	292
Accounts receivable	946	639
Inventories	72	26
Fair value of financial instruments	13	4
Income taxes receivable	11	56
Assets of discontinued operations	—	7
Investments and other current assets	49	40
Total current assets	2,364	1,064
Property and equipment, at cost, based on the full cost method of accounting for oil and gas properties ($3,336 and $2,289 excluded from amortization in 2003 and 2002, respectively)	28,546	18,786
Less accumulated depreciation, depletion and amortization	10,212	7,934
	18,334	10,852
Investment in ChevronTexaco Corporation common stock, at fair value	613	472
Fair value of financial instruments	14	1
Goodwill	5,477	3,555
Other assets	360	281
Total assets	$27,162	16,225
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable:		
Trade	$ 859	376
Revenues and royalties due to others	315	261
Income taxes payable	15	9
Current portion of long-term debt	338	—
Deferred revenue	56	—
Accrued interest payable	130	119
Merger related expenses payable	21	12
Fair value of financial instruments	153	151
Current portion of asset retirement obligation	42	—
Accrued expenses and other current liabilities	142	114
Total current liabilities	2,071	1,042
Other liabilities	349	323
Asset retirement obligation, long-term	629	—
Debentures exchangeable into shares of ChevronTexaco Corporation common stock	677	662
Other long-term debt	7,903	6,900
Preferred stock of a subsidiary	55	—
Fair value of financial instruments	52	18
Deferred income taxes	4,370	2,627
Stockholders' equity:		
Preferred stock of $1.00 par value. Authorized 4,500,000 shares; issued 1,500,000 ($150 million aggregate liquidation value)	1	1
Common stock of $.10 par value. Authorized 800,000,000 shares; issued 239,767,000 in 2003 and 160,461,000 in 2002	24	16
Additional paid-in capital	9,066	5,178
Retained earnings (accumulated deficit)	1,614	(84)
Accumulated other comprehensive income (loss)	569	(267)
Deferred compensation and other	(32)	(3)

Treasury stock, at cost: 3,677,000 shares in 2003 and 3,704,000 shares in 2002	(186)	(188)
Total stockholders' equity	11,056	4,653
Commitments and contingencies (Note 14)		
Total liabilities and stockholders' equity	$27,162	16,225

See accompanying notes to consolidated financial statements.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

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

See accompanying notes to consolidated financial statements.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS — (Continued)

	Year Ended December 31,		
	2003	2002	2001
	(In millions, except per share amounts)		
Basic net earnings per share:			
Earnings from continuing operations	$8.24	0.32	0.09
Net results of discontinued operations	—	0.29	0.25
Cumulative effect of change in accounting principle, net of tax	0.08	—	0.39
Net earnings	$8.32	0.61	0.73
Diluted net earnings per share:			
Earnings from continuing operations	$8.00	0.32	0.09
Net results of discontinued operations	—	0.29	0.25
Cumulative effect of change in accounting principle, net of tax	0.07	—	0.38
Net earnings	$8.07	0.61	0.72
Weighted average common shares outstanding:			
Basic	209	155	128
Diluted	217	156	130

See accompanying notes to consolidated financial statements.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY AND COMPREHENSIVE INCOME (LOSS)

	Preferred Stock	Common Stock	Additional Paid-In Capital	Retained Earnings (Accumulated Deficit)	Accumulated Other Comprehensive Income (Loss)	Deferred Compensation and Other	Treasury Stock	Total Stockholders' Equity
					(In millions)			
Balance as of December 31, 2000	$ 1	13	3,564	(215)	(85)	(1)	—	3,277
Comprehensive income:								
Net earnings	—	—	—	103	—	—	—	103
Other comprehensive income (loss), net of tax:								
Foreign currency translation adjustments	—	—	—	—	(107)	—	—	(107)
Cumulative effect of change in accounting principle	—	—	—	—	(37)	—	—	(37)
Reclassification adjustment for derivative gains reclassified into oil and gas sales	—	—	—	—	(20)	—	—	(20)
Change in fair value of financial instruments	—	—	—	—	216	—	—	216
Minimum pension liability adjustment	—	—	—	—	(17)	—	—	(17)
Unrealized gain on marketable securities	—	—	—	—	22	—	—	22
Other comprehensive income								57
Comprehensive income								160
Stock issued	—	—	48	—	—	—	—	48
Stock repurchased	—	—	(14)	—	—	—	(190)	(204)
Tax benefit related to employee stock options	—	—	12	—	—	—	—	12
Dividends on common stock	—	—	—	(25)	—	—	—	(25)
Dividends on preferred stock	—	—	—	(10)	—	—	—	(10)
Amortization of restricted stock awards	—	—	—	—	—	1	—	1
Balance as of December 31, 2001	1	13	3,610	(147)	(28)	—	(190)	3,259
Comprehensive loss:								
Net earnings	—	—	—	104	—	—	—	104
Other comprehensive income (loss), net of tax:								
Foreign currency translation adjustments	—	—	—	—	46	—	—	46
Reclassification adjustment for derivative gains reclassified into oil and gas sales	—	—	—	—	(39)	—	—	(39)
Change in fair value of financial instruments	—	—	—	—	(217)	—	—	(217)
Minimum pension liability adjustment	—	—	—	—	(54)	—	—	(54)
Unrealized loss on marketable securities	—	—	—	—	(103)	—	—	(103)
Impairment of marketable securities	—	—	—	—	128	—	—	128
Other comprehensive loss								(239)
Comprehensive loss								(135)
Stock issued	—	3	1,559	—	—	—	2	1,564
Tax benefit related to employee stock options	—	—	6	—	—	—	—	6
Dividends on common stock	—	—	—	(31)	—	—	—	(31)
Dividends on preferred stock	—	—	—	(10)	—	—	—	(10)
Grant of restricted stock awards	—	—	3	—	—	(3)	—	—
Balance as of December 31, 2002	1	16	5,178	(84)	(267)	(3)	(188)	4,653
Comprehensive income:								
Net earnings	—	—	—	1,747	—	—	—	1,747
Other comprehensive income (loss), net of tax:								
Foreign currency translation adjustments	—	—	—	—	766	—	—	766
Reclassification adjustment for derivative losses reclassified into oil and gas sales	—	—	—	—	198	—	—	198
Change in fair value of financial instruments	—	—	—	—	(236)	—	—	(236)
Minimum pension liability adjustment	—	—	—	—	19	—	—	19
Unrealized gain on marketable securities	—	—	—	—	89	—	—	89
Other comprehensive income								836
Comprehensive income								2,583
Stock issued	—	7	3,824	—	—	—	2	3,833
Tax benefit related to employee stock options	—	—	31	—	—	—	—	31
Dividends on common stock	—	—	—	(39)	—	—	—	(39)
Dividends on preferred stock	—	—	—	(10)	—	—	—	(10)
Grant of restricted stock awards	—	1	33	—	—	(34)	—	—
Amortization of restricted stock awards	—	—	—	—	—	2	—	2
Other	—	—	—	—	—	3	—	3

Balance as of December 31, 2003	$ 1	24	9,066	1,614	569	(32)	(186)	11,056

See accompanying notes to consolidated financial statements.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

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

See accompanying notes to consolidated financial statements.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Summary of Significant Accounting Policies

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

Nature of Business and Principles of Consolidation

Devon is engaged primarily in oil and gas exploration, development and production, and the acquisition of properties. Such activities domestically are concentrated in four geographic areas:

- the Permian Basin within Texas and New Mexico;
- the Rocky Mountains area of the United States stretching from the Canadian Border into northern New Mexico;
- the Mid-Continent area of the central and southern United States; and
- the Gulf Coast, which includes properties located primarily in the onshore South Texas and South Louisiana areas and offshore in the Gulf of Mexico.

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

Devon also has marketing and midstream operations which are responsible for marketing natural gas, crude oil and NGLs, and the construction and operation of pipelines, storage and treating facilities and gas processing plants. These services are performed for Devon as well as for unrelated third parties.

The accounts of Devon's wholly owned subsidiaries are included in the accompanying consolidated financial statements. All significant intercompany accounts and transactions have been eliminated in consolidation.

Use of Estimates in the Preparation of Financial Statements

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Significant items subject to such estimates and assumptions include the carrying value of oil and gas properties, goodwill impairment assessment, asset retirement obligations, deferred income taxes, valuation of derivative instruments, and obligations related to employee benefits. Actual amounts could differ from those estimates.

Property and Equipment

Devon follows the full cost method of accounting for its oil and gas properties. Accordingly, all costs incidental to the acquisition, exploration and development of oil and gas properties, including costs of undeveloped leasehold, dry holes and leasehold equipment, are capitalized. Internal costs incurred that are directly identified with acquisition, exploration and development activities undertaken by Devon for its own account, and which are not related to production, general corporate overhead or similar activities, are also capitalized. Interest costs incurred and attributable to unproved oil and gas properties under current evaluation and major development projects of oil and gas properties are also capitalized.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Unproved properties are excluded from amortized capitalized costs until it is determined whether or not proved reserves can be assigned to such properties. Devon assesses its unproved properties for impairment quarterly. Significant unproved properties are assessed individually. Costs of insignificant unproved properties are transferred to amortizable costs over average holding periods ranging from three years for onshore properties to seven years for offshore properties.

Net capitalized costs are limited to the estimated future net revenues, discounted at 10% per annum, from proved oil, natural gas and natural gas liquids reserves plus the cost of properties not subject to amortization. Such limitations are imposed separately on a country-by-country basis and are tested quarterly. Capitalized costs are depleted by an equivalent unit-of-production method, converting gas to oil at the ratio of six thousand cubic feet of natural gas to one barrel of oil. Depletion is calculated using the capitalized costs, including estimated asset retirement costs, plus the estimated future expenditures (based on current costs) to be incurred in developing proved reserves, net of estimated salvage values. No gain or loss is recognized upon disposal of oil and gas properties unless such disposal significantly alters the relationship between capitalized costs and proved reserves in a particular country. All costs related to production activities, including workover costs incurred solely to maintain or increase levels of production from an existing completion interval, are charged to expense as incurred.

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

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

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

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

mineral rights as separate intangible assets, the amounts included in oil and gas properties on the balance sheet that would be reclassified are not expected to exceed the following amounts:

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

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

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

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

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

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

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

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

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

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

Marketable Securities and Other Investments

Devon reports investments in debt and equity and other short-term securities at fair value, except for debt securities in which management has the ability and intent to hold until maturity. Devon's only significant investment security is the investment in approximately 7.1 million shares of ChevronTexaco Corporation ("ChevronTexaco") common stock which is reported at fair value. Except for unrealized losses that are determined to be "other than temporary", the tax effected unrealized gain or loss on the investment in ChevronTexaco common stock is recognized in other comprehensive income (loss) and reported as a separate component of stockholders' equity.

Goodwill

Goodwill represents the excess of the purchase price of business combinations over the fair value of the net assets acquired. Effective July 1, 2001, Devon adopted the provisions of SFAS No. 141, *Business*

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Combinations, and certain provisions of SFAS No. 142, *Goodwill and Other Intangible Assets*. Effective January 1, 2002 Devon adopted the remaining provisions of SFAS No. 142. Goodwill and intangible assets with indefinite useful lives are not amortized but are instead tested for impairment at least annually. As of January 1, 2002, Devon had unamortized goodwill in the amount of $2.2 billion, which was subject to the transitional goodwill impairment assessment provisions of SFAS No. 142. During 2002, goodwill increased to $3.6 billion at December 31, 2002 due primarily to the January 2002 Mitchell merger. As a result of the April 2003 Ocean merger and the effects of changes in the Canadian-to-U.S. dollar foreign exchange rates, goodwill increased $1.5 billion and $0.4 billion, respectively, to $5.5 billion at the end of 2003. Devon performed its transitional impairment assessment of goodwill as of January 1, 2002 and its annual assessments of goodwill in the fourth quarter of 2003 and 2002. Based on these assessments, no impairment of goodwill was required.

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

	Year Ended December 31,		
	2003	2002	2001
	(In millions, except per share data)		
Net earnings applicable to common shareholders, as reported	$1,737	94	93
Add back amortization of goodwill	—	—	34
Net earnings applicable to common shareholders, as adjusted	$1,737	94	127
Basic earnings per share:			
Net earnings applicable to common shareholders, as reported	$ 8.32	0.61	0.73
Amortization of goodwill	—	—	0.26
Net earnings applicable to common shareholders, as adjusted	$ 8.32	0.61	0.99
Diluted earnings per share:			
Net earnings applicable to common shareholders, as reported	$ 8.07	0.61	0.72
Amortization of goodwill	—	—	0.26
Net earnings applicable to common shareholders, as adjusted	$ 8.07	0.61	0.98

Revenue Recognition and Gas Balancing

Oil, gas and NGL revenues are recognized when the products are sold. During the course of normal operations, Devon and other joint interest owners of natural gas reservoirs will take more or less than their respective ownership share of the natural gas volumes produced. These volumetric imbalances are monitored over the lives of the wells' production capability. If an imbalance exists at the time the wells' reserves are depleted, settlements are made among the joint interest owners under a variety of arrangements.

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

Marketing and midstream revenues are recorded on the sales method at the time products are sold or services are provided to third parties. Revenues and expenses attributable to Devon's NGL purchase and processing contracts are reported on a gross basis since Devon takes title to the products and has risks and rewards of ownership.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Major Purchasers

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

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

Hedging Activities

Devon enters into oil and gas financial instruments to manage its exposure to oil and gas price volatility. Devon has also entered into interest rate swaps to manage its exposure to interest rate volatility. The interest rate swaps mitigate either the effects of interest rate fluctuations on interest expense for variable-rate debt instruments, or the debt fair values for fixed-rate debt.

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

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

By using derivative instruments to hedge exposures to changes in commodity prices and interest rates, Devon exposes itself to credit risk and market risk. Credit risk is the failure of the counterparty to perform under the terms of the derivative contract. To mitigate this risk, the hedging instruments are placed with counterparties that Devon believes are minimal credit risks. It is Devon's policy to only enter into derivative contracts with investment grade rated counterparties deemed by management to be competent and competitive market makers.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Market risk is the change in the value of a derivative instrument that results from a change in commodity prices or interest rates. The market risk associated with commodity price and interest rate contracts is managed by establishing and monitoring parameters that limit the types and degree of market risk that may be undertaken. The oil and gas reference prices upon which the commodity hedging instruments are based reflect various market indices that have a high degree of historical correlation with actual prices received by Devon.

Devon does not hold or issue derivative instruments for speculative trading purposes. Devon's commodity costless price collars and price swaps have been designated as cash flow hedges. Changes in the fair value of these derivatives are reported on the balance sheet in AOCI. These amounts are reclassified to oil and gas sales when the forecasted transaction takes place.

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

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

Stock Options

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

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

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

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

Income Taxes

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

General and Administrative Expenses

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

Net Earnings Per Common Share

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

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

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

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

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

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

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

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

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Foreign Currency Translation Adjustments

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

Statements of Cash Flows

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

Commitments and Contingencies

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

Environmental expenditures are expensed or capitalized in accordance with accounting principles generally accepted in the United States of America. Liabilities for these expenditures are recorded when it is probable that obligations have been incurred and the amounts can be reasonably estimated. Reference is made to Note 14 for a discussion of amounts recorded for these liabilities.

Impact of Recently Issued Accounting Standards Not Yet Adopted

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

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

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

2. Business Combinations and Pro Forma Information

Ocean Energy, Inc.

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

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

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

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

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Mitchell Energy & Development Corp.

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

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

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

	(In millions, except share price)
Calculation and allocation of purchase price:	
Shares of Devon common stock issued to Mitchell stockholders	30
Average Devon stock price	$50.95
Fair value of common stock issued	$1,512
Cash paid to Mitchell stockholders, calculated at $31 per outstanding common share of Mitchell	1,573
Fair value of Devon common stock and cash to be issued to Mitchell stockholders	3,085
Plus estimated merger costs incurred	84
Plus fair value of Mitchell employee stock options assumed by Devon	27
Total purchase price	3,196
Plus fair value of liabilities assumed by Devon:	
Current liabilities	190
Long-term debt	506
Other long-term liabilities	128
Deferred income taxes	798
Total purchase price plus liabilities assumed	$4,818
Fair value of assets acquired by Devon:	
Current assets	$ 169
Proved oil and gas properties	1,535
Unproved oil and gas properties	639
Marketing and midstream facilities and equipment	1,000
Other property and equipment	15
Other assets	103
Goodwill (none deductible for income taxes)	1,357
Total fair value of assets acquired	$4,818

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Pro Forma Information

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

	Pro Forma Information Year Ended December 31,	
	2003	2002
	(In millions, except per share amounts and production volumes) (Unaudited)	
Revenues:		
Oil sales	$1,840	1,549
Gas sales	4,155	2,655
Natural gas liquids sales	416	304
Marketing and midstream revenues	1,461	1,069
Total revenues	7,872	5,577
Operating Costs and Expenses:		
Lease operating expenses	948	835
Transportation costs	219	190
Production taxes	219	148
Marketing and midstream operating costs and expenses	1,174	873
Depreciation, depletion and amortization of property and equipment	1,984	1,862
Accretion of asset retirement obligation	38	—
General and administrative expenses	340	321
Reduction of carrying value of oil and gas properties	111	727
Total operating costs and expenses	5,033	4,956
Earnings from operations	2,839	621

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

	Pro Forma Information Year Ended December 31,	
	2003	2002
	(In millions, except per share amounts and production volumes) (Unaudited)	
Other Income (Expenses):		
Interest expense	(515)	(582)
Dividends on subsidiary's preferred stock	(3)	(3)
Effects of changes in foreign currency exchange rates	69	1
Change in fair value of financial instruments	1	28
Impairment of ChevronTexaco Corporation common stock	—	(205)
Other income	40	32
Net other expenses	(408)	(729)
Earnings (loss) from continuing operations before income taxes and cumulative effect of change in accounting principle	2,431	(108)
Income Tax Expense (Benefit):		
Current	219	47
Deferred	372	(199)
Total income tax expense (benefit)	591	(152)
Earnings from continuing operations before cumulative effect of change in accounting principle	1,840	44
Discontinued Operations:		
Results of discontinued operations before income taxes (including net gain on disposal of $31 million in 2002)	—	54
Total income tax expense	—	9
Net results of discontinued operations	—	45
Earnings before cumulative effect of change in accounting principle	1,840	89
Cumulative effect of change in accounting principle	29	—
Net earnings	1,869	89
Preferred stock dividends	10	10
Net earnings applicable to common stockholders	$1,859	79
Basic earnings per average common share outstanding:		
Earnings from continuing operations	$ 7.90	0.15
Net results of discontinued operations	—	0.20
Cumulative effect of change in accounting principle	0.12	—
Net earnings	$ 8.02	0.35

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

	Pro Forma Information Year Ended December 31,	
	2003	2002
	(In millions, except per share amounts and production volumes) (Unaudited)	
Diluted earnings per average common share outstanding:		
Earnings from continuing operations	$7.69	0.14
Net results of discontinued operations	—	0.19
Cumulative effect of change in accounting principle	0.12	—
Net earnings	$7.81	0.33
Weighted average common shares outstanding — basic	232	229
Weighted average common shares outstanding — diluted	240	236
Production volumes:		
Oil (MMBbls)	73	70
Gas (Bcf)	934	927
NGLs (MMBbls)	23	22
MMBoe	251	247

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

3. Comprehensive Income or Loss

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

	Foreign Currency Translation Adjustments	Change in Fair Value of Financial Instruments	Minimum Pension Liability Adjustments	Unrealized Gain (Loss) on Marketable Securities	Total
			(In millions)		
Balance as of December 31, 2000	$ (38)	—	—	(47)	(85)
2001 activity	(107)	243	(28)	36	144
Deferred taxes	—	(84)	11	(14)	(87)
2001 activity, net of deferred taxes	(107)	159	(17)	22	57
Balance as of December 31, 2001	(145)	159	(17)	(25)	(28)
2002 activity	46	(379)	(85)	41	(377)
Deferred taxes	—	123	31	(16)	138
2002 activity, net of deferred taxes	46	(256)	(54)	25	(239)
Balance as of December 31, 2002	(99)	(97)	(71)	—	(267)
2003 activity	894	(41)	28	141	1,022
Deferred taxes	(128)	3	(9)	(52)	(186)
2003 activity, net of deferred taxes	766	(38)	19	89	836
Balance as of December 31, 2003	$ 667	(135)	(52)	89	569

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

4. Supplemental Cash Flow Information

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

	Year Ended December 31,		
	2003	2002	2001
		(In millions)	
Interest paid	$508	248	118
Income taxes paid (refunded)	$123	(12)	185

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

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

	Ocean Merger	Mitchell Merger	Anderson Acquisition
		(In millions)	
Value of common stock issued	$3,546	1,512	—
Convertible preferred stock assumed	64	—	—
Employee stock options assumed	124	27	—
Liabilities assumed	2,382	824	1,301
Deferred tax liability created	989	798	1,394
Fair value of assets acquired with non-cash consideration	$7,105	3,161	2,695

5. Accounts Receivable

The components of accounts receivable included the following:

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

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

6. Property and Equipment and Asset Retirement Obligations

Property and equipment included the following:

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

The costs not subject to amortization relate to unproved properties which are excluded from amortized capital costs until it is determined whether or not proved reserves can be assigned to such properties. The excluded properties are assessed for impairment at least annually. Subject to industry conditions, evaluation of most of these properties, and the inclusion of their costs in the amortized capital costs is expected to be completed within five years.

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

	Year Ended December 31,		
	2003	2002	2001
	(In millions)		
Depreciation, depletion and amortization of oil and gas properties	$1,668	1,106	793
Depreciation and amortization of other property and equipment	118	97	30
Amortization of other assets	7	8	8
Total	$1,793	1,211	831

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

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

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

7. Investment in ChevronTexaco Corporation Common Stock

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

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

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

Beginning in July 2002, the market value of ChevronTexaco common stock began a significant decline. The price per share decreased from $88.50 at June 30, 2002, to $69.25 per share at September 30, 2002, and to $66.48 per share at December 31, 2002. The year-end price of $66.48 represented a 25% decline since June 30, 2002, and a 30% decline from the original valuation in August 1999. As a result of the decline in value during the fourth quarter of 2002, Devon determined that the decline was other than

temporary, as that term is defined by accounting rules. Therefore, the $205 million cumulative decrease in the value of the ChevronTexaco common shares from the initial acquisition in August 1999 to December 31, 2002, was recorded as a noncash charge to Devon's results of operations in the fourth quarter of 2002. Net of the applicable tax benefit, the charge reduced net earnings by $128 million.

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

8. Long-Term Debt and Related Expenses

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

	December 31,	
	2003	2002
	(In millions)	
Borrowings under credit facilities with banks	$ —	—
Commercial paper borrowings	—	—
$3 billion term loan credit facility due October 15, 2006	635	1,135
Debentures exchangeable into shares of ChevronTexaco Corporation common stock:		
4.90% due August 15, 2008	444	444
4.95% due August 15, 2008	316	316
Discount on exchangeable debentures	(83)	(98)
Zero coupon convertible senior debentures exchangeable into shares of Devon common stock, due June 27, 2020	404	388
Other debentures and notes:		
6.75% due February 15, 2004	211	211
8.05% due June 15, 2004	125	125
7.625% due July 1, 2005	125	—
7.25% due July 18, 2005	135	111
10.25% due November 1, 2005	236	236
2.75% due August 1, 2006	500	—
6.55% due August 2, 2006	155	127
4.375% due October 1, 2007	400	—
10.125% due November 15, 2009	177	177
6.75% due March 15, 2011	400	400

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

	December 31,	
	2003	2002
	(In millions)	
6.875% due September 30, 2011	1,750	1,750
7.25% due October 1, 2011	350	—
8.25% due July 1, 2018	125	—
7.50% due September 15, 2027	150	—
7.875% due September 30, 2031	1,250	1,250
7.95% due April 15, 2032	1,000	1,000
Other	4	—
Fair value adjustment on debt related to interest rate swaps	27	5
Net (discount) premium on other debentures and notes	82	(15)
	8,918	7,562
Less amount classified as current	338	—
Long-term debt	$8,580	7,562

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

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

Credit Facilities with Banks

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

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

Devon may borrow funds under the $275 million Canadian Facility until June 2, 2004 (the “Canadian Facility Revolving Period”). Devon may request that the Canadian Facility Revolving Period be extended an additional 364 days by notifying the agent bank of such request between 30 and 60 days prior to the end of the Canadian Facility Revolving Period. Debt outstanding as of the end of the Canadian Facility

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Revolving Period is payable in semiannual installments of 2.5% each for the following five years, with the final installment due five years and one day following the end of the Canadian Facility Revolving Period. On December 31, 2003 and 2002, there were no borrowings under the $275 million Canadian facility. The available capacity under the Canadian Facility as of December 31, 2003, net of outstanding letters of credit, was approximately $214 million.

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

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

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

Commercial Paper

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

$3 Billion Term Loan Credit Facility

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

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

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

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Exchangeable Debentures

The exchangeable debentures consist of $444 million of 4.90% debentures and $316 million of 4.95% debentures. The exchangeable debentures were issued on August 3, 1998 and mature August 15, 2008. The exchangeable debentures were callable beginning August 15, 2000, initially at 104.0% of principal and at prices declining to 100.5% of principal on or after August 15, 2007. The exchangeable debentures are exchangeable at the option of the holders at any time prior to maturity, unless previously redeemed, for shares of ChevronTexaco common stock. In lieu of delivering ChevronTexaco common stock to an exchanging debenture holder, Devon may, at its option, pay to such holder an amount of cash equal to the market value of the ChevronTexaco common stock. At maturity, holders who have not exercised their exchange rights will receive an amount in cash equal to the principal amount of the debentures.

As of December 31, 2003, Devon beneficially owned approximately 7.1 million shares of ChevronTexaco common stock. These shares have been deposited with an exchange agent for possible exchange for the exchangeable debentures. Each $1,000 principal amount of the exchangeable debentures is exchangeable into 9.3283 shares of ChevronTexaco common stock, an exchange rate equivalent to $107.20 per share of ChevronTexaco stock.

The exchangeable debentures were assumed as part of the PennzEnergy merger. The fair values of the exchangeable debentures were determined as of August 17, 1999, based on market quotations. Under SFAS No. 133, the total fair value of the debentures has been allocated between the interest-bearing debt and the option to exchange ChevronTexaco common stock that is embedded in the debentures. Accordingly, a discount was recorded on the debentures and is being accreted using the effective interest method which raised the effective interest rate on the debentures to 7.76%.

Zero Coupon Convertible Debentures

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

Other Debentures and Notes

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

6.75% Senior Notes due February 15, 2004

Devon assumed these senior notes in connection with the Mitchell merger,. The fair value of these senior notes approximated the face value. As a result, no premium or discount was recorded on these senior notes.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

8.05% Notes due June 15, 2004

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

Ocean Debt

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

Debt Assumed	April 25, 2003 Fair Value Of Debt Assumed	Effective Rate Of Debt Assumed
	(In millions)	
Revolving credit line	$ 160	
Note payable	50	
Senior notes and senior subordinated notes:		
7.875% due August 2003 (principal of $100 million)	102	4.8%
7.625% due July 2005 (principal of $125 million)	139	3.0%
4.375% due October 2007 (principal of $400 million)	410	3.8%
8.375% due July 2008 (principal of $200 million)	208	7.4%
7.250% due September 2011 (principal of $350 million)	406	4.9%
8.250% due July 2018 (principal of $125 million)	147	5.5%
7.500% due September 2027 (principal of $150 million)	169	6.5%
Other	6	
	1,797	
Less amount classified as current as of April 25, 2003	361	
Long-term debt	$1,436	

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

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

Anderson Debt

In connection with the Anderson acquisition, Devon assumed $702 million of senior notes. The table below summarizes the debt assumed which remains outstanding, the fair value of the debt at October 15, 2001, and the effective interest rate of the debt assumed after determining the fair values of the respective

notes using October 15, 2001, market interest rates. The premiums and discounts are being amortized or accreted using the effective interest method. All of the notes are general unsecured obligations of Devon.

Debt Assumed	Fair Value of Debt Assumed	Effective Rate of Debt Assumed
	(In millions)	
7.25% senior notes due 2005	$116	6.3%
6.55% senior notes due 2006	$129	6.5%
6.75% senior notes due 2011	$400	6.8%

2.75% Notes due August 1, 2006

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

10.25% Debentures due November 1, 2005 and 10.125% Debentures due November 15, 2009

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

6.875% Notes due September 30, 2011 and 7.875% Debentures due September 30, 2031

On October 3, 2001, Devon, through Devon Financing, sold these notes and debentures which are unsecured and unsubordinated obligations of Devon Financing. Devon has fully and unconditionally guaranteed on an unsecured and unsubordinated basis the obligations of Devon Financing under the debt securities. The proceeds from the issuance of these debt securities were used to fund a portion of the Anderson acquisition. The $3 billion of debt securities were structured in a manner that results in an expected weighted average after-tax borrowing rate of approximately 1.65%.

7.95% Notes due April 15, 2032

On March 25, 2002, Devon sold these notes which are unsecured and unsubordinated obligations of Devon. The net proceeds received, after discounts and issuance costs, were $986 million and were partially used to pay down $820 million on Devon's $3 billion term loan credit facility. The remaining $166 million of net proceeds was used in June 2002 to partially fund the early extinguishment of $175 million of 8.75% senior subordinated notes due June 15, 2007. The notes were redeemed at 104.375% of principal, or approximately $183 million.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Interest Expense

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

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

Effects of Changes in Foreign Currency Exchange Rates

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

9. Income Taxes

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

Types of Carryforward	Years of Expiration	Carryforward Amounts
		(In millions)
Net operating loss — U.S. federal	2014 - 2023	$611
Net operating loss — various states	2004 - 2022	$346
Net operating loss — Canada	2005 - 2009	$473
Net operating loss — Azerbaijan	Indefinite	$ 67
Net operating loss — China	2004 - 2008	$ 19
Minimum tax credits	Indefinite	$ 56

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

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

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

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

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

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

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

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

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

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

	December 31,	
	2003	2002
	(In millions)	
Deferred tax assets:		
Net operating loss carryforwards	$ 416	78
Minimum tax credit carryforwards	56	164
Fair value of financial instruments	44	46
Asset retirement obligations	281	—
Pension benefit obligation	85	42
Other	139	53
Total deferred tax assets	1,021	383
Deferred tax liabilities:		
Property and equipment, principally due to nontaxable business combinations, differences in depreciation, and the expensing of intangible drilling costs for tax purposes	(5,052)	(2,863)
ChevronTexaco Corporation common stock	(190)	(147)
Long-term debt	(102)	—
Other	(47)	—
Total deferred tax liabilities	(5,391)	(3,010)
Net deferred tax liability	$(4,370)	(2,627)

As shown in the above table, Devon has recognized $1.0 billion of deferred tax assets as of December 31, 2003. Such amount consists of $416 million of various carryforwards available to offset future income taxes. The carryforwards include federal net operating loss carryforwards, the majority of which do not begin to expire until 2014, state net operating loss carryforwards which expire primarily between 2004 and 2022, Canadian carryforwards which expire primarily between 2005 and 2009, Azerbaijani carryforwards which have no expiration, Chinese carryforwards which expire primarily between 2004 and 2008 and minimum tax credit carryforwards which have no expiration. The tax benefits of carryforwards are recorded as an asset to the extent that management assesses the utilization of such carryforwards to be “more likely than not.” When the future utilization of some portion of the carryforwards is determined not to be “more likely than not,” a valuation allowance is provided to reduce the recorded tax benefits from such assets.

Devon expects the tax benefits from the net operating loss carryforwards to be utilized between 2004 and 2009. Such expectation is based upon current estimates of taxable income during this period, considering limitations on the annual utilization of these benefits as set forth by tax regulations. Significant changes in such estimates caused by variables such as future oil and gas prices or capital expenditures could alter the timing of the eventual utilization of such carryforwards. There can be no assurance that Devon will generate any specific level of continuing taxable earnings. However, management believes that

Devon's future taxable income will more likely than not be sufficient to utilize substantially all its tax carryforwards prior to their expiration.

10. Preferred Stock of a Subsidiary

At December 31, 2003, a subsidiary of Devon created in the Ocean merger had 38,000 shares of convertible preferred stock. In January 2004, these shares of convertible preferred stock were canceled and converted to 1,098,580 shares of Devon common stock pursuant to an automatic conversion feature of the preferred stock. The automatic conversion feature was triggered when the closing price of Devon common stock equaled or exceeded the forced conversion price of $52.39 for 20 consecutive trading days.

11. Stockholders' Equity

The authorized capital stock of Devon consists of 800 million shares of common stock, par value $.10 per share (the "Common Stock"), and 4.5 million shares of preferred stock, par value $1.00 per share. The preferred stock may be issued in one or more series, and the terms and rights of such stock will be determined by the Board of Directors.

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

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

Devon's Board of Directors has designated a certain number of shares of the preferred stock as Series A Junior Participating Preferred Stock (the "Series A Junior Preferred Stock") in connection with the adoption of the shareholder rights plan described later in this note. Effective January 22, 2002, the Board voted to increase the designated shares from one million to two million. At December 31, 2003, there were no shares of Series A Junior Preferred Stock issued or outstanding. The Series A Junior Preferred Stock is entitled to receive cumulative quarterly dividends per share equal to the greater of $10 or 100 times the aggregate per share amount of all dividends (other than stock dividends) declared on Common Stock since the immediately preceding quarterly dividend payment date or, with respect to the first payment date, since the first issuance of Series A Junior Preferred Stock. Holders of the Series A Junior Preferred Stock are entitled to 100 votes per share (subject to adjustment to prevent dilution) on all matters submitted to a vote of the stockholders. The Series A Junior Preferred Stock is neither redeemable nor convertible. The Series A Junior Preferred Stock ranks prior to the Common Stock but junior to all other classes of Preferred Stock.

Stock Option Plans

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

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

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

The exercise price of stock options granted under the 2003 Plan may not be less than the estimated fair market value of the stock at the date of grant. Options granted are exercisable during a period established for each grant, which period may not exceed 8 years from the date of grant. Under the 2003 Plan, the grantee must pay the exercise price in cash or in common stock, or a combination thereof, at the time that the option is exercised. The 2003 Plan is administered by a committee comprised of non-management members of the Board of Directors. The 2003 Plan expires on April 25, 2013. As of December 31, 2003, there were 1,487,000 options outstanding under the 2003 Plan. There were 10,360,000 options available for future grants as of December 31, 2003.

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

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

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

	Options Outstanding		Options Exercisable	
	Number Outstanding	Weighted Average Exercise Price	Number Exercisable	Weighted Average Exercise Price
	(In thousands)		(In thousands)	
Balance at December 31, 2000	7,356	$41.84	6,025	$40.72
Options granted	2,601	$35.43		
Options exercised	(1,505)	$31.13		
Options forfeited	(268)	$62.77		
Balance at December 31, 2001	8,184	$41.09	5,516	$41.93
Options granted	2,807	$45.77		
Options assumed in the Mitchell merger	1,554	$26.82		
Options exercised	(899)	$29.33		
Options forfeited	(415)	$47.12		
Balance at December 31, 2002	11,231	$41.00	6,991	$40.05
Options granted	1,504	$52.75		
Options assumed in the Ocean merger	7,926	$39.69		
Options exercised	(4,866)	$33.50		
Options forfeited	(450)	$52.11		
Balance at December 31, 2003	15,345	$43.53	11,460	$42.61

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

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

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

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number Outstanding	Weighted Average Remaining Life	Weighted Average Exercise Price	Number Exercisable	Weighted Average Exercise Price
	(In thousands)			(In thousands)	
$ 9.68 - $30.94	2,172	2.52 Years	$20.91	2,172	$20.91
$31.00 - $36.90	2,560	5.23 Years	$35.01	1,761	$35.09
$37.22 - $45.08	2,096	3.97 Years	$42.78	2,049	$42.87
$45.10 - $46.09	2,753	6.27 Years	$46.03	1,234	$45.96
$46.27 - $51.70	2,317	5.05 Years	$50.32	2,139	$50.30
$51.75 - $56.19	2,339	4.80 Years	$53.74	1,003	$54.94
$56.68 - $89.66	1,108	3.36 Years	$66.96	1,102	$67.01
	15,345	4.65 Years	$43.53	11,460	$42.61

Shareholder Rights Plan

Under Devon's shareholder rights plan, stockholders have one right for each share of Common Stock held. The rights become exercisable and separately transferable 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.

Dividends

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

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

12. Financial Instruments

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

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

The following methods and assumptions were used to estimate the fair values of the financial instruments in the above table. The carrying values of cash and cash equivalents, accounts receivable and accounts payable (including income taxes payable and accrued expenses) included in the accompanying consolidated balance sheets approximated fair value at December 31, 2003 and 2002.

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

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

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

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

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

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

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

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

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

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

Price Swaps

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

Oil Production

Year	Bbls/Day	Price per Bbl
2004	64,000	$26.95
2005	22,000	$26.84

Gas Production

Year	Mcf/Day	Price per Mcf
2004	8,435	$3.10
2005	7,343	$2.97

Costless Price Collars

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

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

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

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

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

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

Oil Production

		Weighted Average	
Year	Bbls/Day	Floor Price per Bbl	Ceiling Price per Bbl
2004	77,000	$21.90	$30.28
2005	50,000	$22.23	$28.23

Gas Production

		Weighted Average	
Year	MMBtu/Day	Floor Price per MMBtu	Ceiling Price per MMBtu
2004	1,194,945	$4.02	$7.43
2005	94,548	$3.83	$7.20

Interest Rate Swaps

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

Debt Instrument	Notional Amount	Floating Rate
4.375% senior notes due in 2007	$400	LIBOR plus 40 basis points
10.25% bond due in 2005	$235	LIBOR plus 711 basis points
8.05% senior notes due in 2004	$125	LIBOR plus 336 basis points
2.75% notes due in 2006	$500	LIBOR less 26.8 basis points
7.625% senior notes due in 2005	$125	LIBOR plus 237 basis points

13. Retirement Plans

Devon has various non-contributory defined benefit pension plans, including qualified plans ("Qualified Plans") and nonqualified plans ("Supplemental Plans"). The Qualified Plans provide

retirement benefits for U.S. and Canadian employees meeting certain age and service requirements. Benefits for the Qualified Plans are based on the employee's years of service and compensation and are funded from assets held in the plans' trusts.

During 2002, Devon established a funding policy regarding the Qualified Plans such that it would contribute the amount of funds necessary so that the Qualified Plans' assets would be approximately equal to the related accumulated benefit obligation by the end of 2004. As of December 31, 2003, the Qualified Plans' total accumulated benefit obligation was $397 million, which was $22 million more than the related assets. Devon's intentions are to fund this deficit during 2004. The actual amount of contributions required during this period will depend on investment returns from the plan assets during the same period as well as changes in long-term interest rates.

The Supplemental Plans provide retirement benefits for certain employees whose benefits under the Qualified Plans are limited by income tax regulations. The Supplemental Plans' benefits are based on the employee's years of service and compensation. For certain Supplemental Plans, Devon has established trusts to fund these plans' benefit obligations. The total values of these trusts were $66 million and $53 million at December 31, 2003 and 2002, respectively, and are included in noncurrent other assets in the consolidated balance sheets. For the remaining Supplemental Plans for which trusts have not been established, benefits are funded from Devon's available cash and cash equivalents.

Devon also has defined benefit postretirement plans ("Postretirement Plans") which provide benefits for substantially all employees. The Postretirement Plans provide medical and, in some cases, life insurance benefits and are, depending on the type of plan, either contributory or non-contributory. Benefit obligations for the Postretirement Plans are estimated based on future cost-sharing changes that are consistent with Devon's expressed intent to increase, where possible, contributions from future retirees. Devon's funding policy for the Postretirement Plans is to fund the benefits as they become payable with available cash and cash equivalents recorded in the consolidated balance sheet.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Benefit Obligations

Devon uses a measurement date of December 31 for its pension and postretirement benefit plans. The following table presents the plans' benefit obligations and the weighted-average actuarial assumptions used to calculate such obligations at December 31, 2003 and 2002. The benefit obligation for pension plans represents the projected benefit obligation, while the benefit obligation for the postretirement benefit plans represents the accumulated benefit obligation. The accumulated benefit obligation differs from the projected benefit obligation in that the former includes no assumption about future compensation levels. The accumulated benefit obligation for pension plans at December 31, 2003 and 2002 was $475 million and $424 million, respectively.

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

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

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Plan Assets

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

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

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

Devon's overall investment objective for its retirement plans' assets is to achieve long-term growth of invested capital to ensure payments of retirement benefits obligations can be funded when required. To assist in achieving this objective, Devon has established certain investment strategies, including target allocation percentages and permitted and prohibited investments, designed to mitigate risks inherent with investing. At December 31, 2003, the target investment allocation for Devon's plan assets is 50% U.S. large cap equity securities; 15% U.S. small cap equity securities, equally allocated between growth and value; 15% international equity securities, equally allocated between growth and value; and 20% debt securities. Derivatives or other speculative investments considered high-risk are generally prohibited.

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

	Target Allocation 2004	Percentage of Plan Assets at Year End	
		2003	2002
Equity securities	80%	79%	75%
Debt securities	20%	19%	23%
Other	0%	2%	2%
Total	100%	100%	100%

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Funded Status

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

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

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

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

	December 31,	
	2003	2002
	(In millions)	
Projected benefit obligation	$571	519
Fair value of plan assets	359	265

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

	December 31,	
	2003	2002
	(In millions)	
Accumulated benefit obligation	$465	415
Fair value of plan assets	359	265

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

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Net Periodic Cost

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

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

The expected rate of return on plan assets was determined by evaluating input from external consultants and economists as well as long-term inflation assumptions. The expected long-term rate of return on plan assets is based on the target allocation of investment types in such assets.

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

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

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Expected Cash Flows

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

	Pension Benefits	Other Postretirement Benefits
	(In millions)	
Employer contributions — 2004	$ 52	8
Benefit payments:		
2004	28	8
2005	29	8
2006	30	8
2007	31	7
2008	33	7
2009 - 2013	192	30

Expected employer contributions included in the table above include amounts related to Devon's Qualified Plans, Supplemental Plans and Postretirement Plans. Of the benefits expected to be paid in 2004, $7 million is expected to be funded from the trusts established for the Supplemental Plans and $8 million is expected to be funded from Devon's available cash and cash equivalents. Expected employer contributions and benefit payments for other postretirement benefits are presented net of employee contributions.

Other Benefit Plans

Devon has incurred certain postemployment benefits to former or inactive employees who are not retirees. These benefits include salary continuance, severance and disability health care and life insurance. The accrued postemployment benefit liability was approximately $6 million at both December 31, 2003 and 2002.

Devon has a 401(k) Incentive Savings Plan which covers all domestic employees. At its discretion, Devon may match a certain percentage of the employees' contributions to the plan. The matching percentage is determined annually by the Board of Directors. Devon's matching contributions to the plan were $10 million, $8 million and $5 million for the years ended December 31, 2003, 2002 and 2001, respectively.

Devon has defined contribution pension plans for its Canadian employees. Devon makes a contribution to each employee which is based upon the employee's base compensation and classification. Such contributions are subject to maximum amounts allowed under the Income Tax Act (Canada). Devon also has a savings plan for its Canadian employees. Under the savings plan, Devon contributes a base percentage amount to all employees and the employee may elect to contribute an additional percentage amount (up to a maximum amount) which is matched by additional Devon contributions. During 2003, 2002 and 2001, Devon's combined contributions to the Canadian defined contribution plan and the Canadian savings plan were $8 million, $8 million and $3 million, respectively.

14. Commitments and Contingencies

Devon is party to various legal actions arising in the normal course of business. Matters that are probable of unfavorable outcome to Devon and which can be reasonably estimated are accrued. Such accruals are based on information known about the matters, Devon's estimates of the outcomes of such

matters and its experience in contesting, litigating and settling similar matters. None of the actions are believed by management to involve future amounts that would be material to Devon's financial position or results of operations after consideration of recorded accruals although actual amounts could differ materially from management's estimate.

Environmental Matters

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

Certain of Devon's subsidiaries acquired in past mergers are involved in matters in which it has been alleged that such subsidiaries are potentially responsible parties ("PRPs") under CERCLA or similar state legislation with respect to various waste disposal areas owned or operated by third parties. As of December 31, 2003, Devon's consolidated balance sheet included $9 million of non-current accrued liabilities, reflected in "Other liabilities," related to these and other environmental remediation liabilities. Devon does not currently believe there is a reasonable possibility of incurring additional material costs in excess of the current accruals recognized for such environmental remediation activities. With respect to the sites in which Devon subsidiaries are PRPs, Devon's conclusion is based in large part on (i) Devon's participation in consent decrees with both other PRPs and the Environmental Protection Agency, which provide for performing the scope of work required for remediation and contain covenants not to sue as protection to the PRPs, (ii) participation in groups as a *de minimis* PRP, and (iii) the availability of other defenses to liability. As a result, Devon's monetary exposure is not expected to be material.

Royalty Matters

Numerous gas producers and related parties, including Devon, have been named in various lawsuits alleging violation of the federal False Claims Act. The suits allege that the producers and related parties used below-market prices, improper deductions, improper measurement techniques and transactions with affiliates which resulted in underpayment of royalties in connection with natural gas and natural gas liquids produced and sold from federal and Indian owned or controlled lands. The principal suit in which Devon is a defendant is *United States ex rel. Wright v. Chevron USA, Inc. et al.* (the "*Wright* case"). The suit was originally filed in August 1996 in the United States District Court for the Eastern District of Texas, but was consolidated in October 2000 with the other suits for pre-trial proceedings in the United States District Court for the District of Wyoming. On July 10, 2003, the District of Wyoming remanded the *Wright* case back to the Eastern District of Texas to resume proceedings. Devon believes that it has acted reasonably, has legitimate and strong defenses to all allegations in the suit, and has paid royalties in good faith. Devon does not currently believe that it is subject to material exposure in association with this lawsuit and no liability has been recorded in connection therewith.

Devon is a defendant in certain private royalty owner litigation filed in Wyoming regarding deductibility of certain post production costs from royalties payable by Devon. The plaintiffs in these lawsuits propose to expand them into county or state-wide class actions relating specifically to transportation and related costs associated with Devon's Wyoming gas production. A significant portion of

such production is, or will be, transported through facilities owned by Thunder Creek Gas Services, L.L.C., of which Devon owns a 75% interest. Devon believes that it has acted reasonably and paid royalties in good faith and in accordance with its obligations under its oil and gas leases and applicable law, and Devon does not believe that it is subject to material exposure in association with this litigation.

Tax Treatment of Exchangeable Debentures

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

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

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

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

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

Other Matters

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

Operating Leases

Devon leases certain office space and equipment under operating lease arrangements. Total rental expense included in general and administrative expenses under operating leases net of sub-lease income was $51 million, $37 million and $17 million in 2003, 2002 and 2001, respectively.

Devon assumed two offshore platform spar leases through the 2003 Ocean merger. The spars are being used in the development of the Nansen and Boomvang fields in the Gulf of Mexico. The operating leases are for 20-year terms and contain various options whereby Devon may purchase the lessors' interests in the spars. Total rental expense included in lease operating expenses under these operating leases was

$11 million in 2003. Devon has guaranteed that the spars will have residual values at the end of the operating leases equal to at least 10% of the fair value of the spars at the inception of the leases. The total guaranteed value is $20 million in 2022. However, such amount may be reduced under the terms of the lease agreements.

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

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

Year Ending December 31,	Office and Equipment Leases	Spar Leases	FPSO Leases
	(In millions)		
2004	$ 47	11	20
2005	40	15	20
2006	36	15	20
2007	28	15	20
2008	24	15	20
Thereafter	85	243	36
Total minimum lease payments	$260	314	136

15. Reduction of Carrying Value of Oil and Gas Properties

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

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

During 2003, 2002 and 2001, Devon reduced the carrying value of its oil and gas properties by $68 million, $651 million and $883 million, respectively, due to the full cost ceiling limitations. The after-

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

tax effect of these reductions in 2003, 2002 and 2001 was $36 million, $371 million and $533 million, respectively. The following table summarizes these reductions by geographic area.

	Year Ended December 31,					
	2003		2002		2001	
	Gross	Net of Taxes	Gross	Net of Taxes	Gross	Net of Taxes
	(In millions)					
United States	$ —	—	—	—	449	281
Canada	—	—	651	371	434	252
International	68	36	—	—	—	—
Total	$ 68	36	651	371	883	533

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

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

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

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

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

16. Discontinued Operations

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

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

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

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

	December 31, 2002
	(In millions)
Major Classes of Assets and Liabilities	
Accounts receivable	$ 7
Total assets	$ 7

	Year Ended December 31,	
	2002	2001
	(In millions)	
Revenues		
Oil sales	$ 72	174
Gas sales	7	12
NGL sales	1	1
Total revenues	$ 80	187

17. Segment Information

Devon manages its business by country. As such, Devon identifies its segments based on geographic areas. Devon has three reportable segments: its operations in the U.S., its operations in Canada, and its international operations outside of North America. Substantially all of these segments' operations involve oil and gas producing activities. Certain information regarding such activities for each segment is included in Note 18.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

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

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

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

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

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

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

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

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

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

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

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

18. Supplemental Information on Oil and Gas Operations (Unaudited)

The following supplemental unaudited information regarding the oil and gas activities of Devon is presented pursuant to the disclosure requirements promulgated by the Securities and Exchange Commission and SFAS No. 69, *Disclosures About Oil and Gas Producing Activities.*

Costs Incurred

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

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

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

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

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

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

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

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

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

Pursuant to the full cost method of accounting, Devon capitalizes certain of its general and administrative expenses which are related to property acquisition, exploration and development activities. Such capitalized expenses, which are included in the costs shown in the preceding tables, were $140 million, $97 million and $77 million in the years 2003, 2002 and 2001, respectively. Also, pursuant to the full cost method of accounting, Devon capitalizes interest costs incurred and attributable to unproved oil and gas properties and major development projects of oil and gas properties. Capitalized interest expenses, which are included in the costs shown in the preceding tables, were $50 million, $4 million and $3 million in the years 2003, 2002 and 2001, respectively.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Results of Operations for Oil and Gas Producing Activities

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

	Total		
	Year Ended December 31,		
	2003	2002	2001
	(In millions, except per equivalent barrel amounts)		
Oil, gas and natural gas liquids sales	$ 5,892	3,317	2,793
Production and operating expenses	(1,282)	(886)	(666)
Depreciation, depletion and amortization	(1,668)	(1,106)	(793)
Accretion of asset retirement obligation	(36)	—	—
Amortization of goodwill	—	—	(34)
General and administrative expenses directly related to oil and gas producing activities	(48)	(29)	(17)
Reduction of carrying value of oil and gas properties	(111)	(651)	(979)
Income tax expense	(895)	(234)	(126)
Results of operations for oil and gas producing activities	$ 1,852	411	178
Depreciation, depletion and amortization per equivalent barrel of production	$ 7.33	5.88	6.30

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

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

	Canada		
	Year Ended December 31,		
	2003	2002	2001
	(In millions, except per equivalent barrel amounts)		
Oil, gas and natural gas liquids sales	$1,654	1,144	481
Production and operating expenses	(395)	(317)	(137)
Depreciation, depletion and amortization	(388)	(364)	(164)
Accretion of asset retirement obligation	(13)	—	—
General and administrative expenses directly related to oil and gas producing activities	(15)	(14)	(6)
Reduction of carrying value of oil and gas properties	—	(651)	(434)
Income tax (expense) benefit	(89)	74	102
Results of operations for oil and gas producing activities	$ 754	(128)	(158)
Depreciation, depletion and amortization per equivalent barrel of production	$ 6.17	5.39	5.74

	International		
	Year Ended December 31,		
	2003	2002	2001
	(In millions, except per equivalent barrel amounts)		
Oil, gas and natural gas liquids sales	$ 436	54	52
Production and operating expenses	(76)	(12)	(17)
Depreciation, depletion and amortization	(196)	(5)	(14)
Accretion of asset retirement obligation	(1)	—	—
General and administrative expenses directly related to oil and gas producing activities	(6)	(1)	(2)
Reduction of carrying value of oil and gas properties	(111)	—	(96)
Income tax (expense) benefit	(31)	(13)	35
Results of operations for oil and gas producing activities	$ 15	23	(42)
Depreciation, depletion and amortization per equivalent barrel of production	$10.52	2.40	6.20

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

Quantities of Oil and Gas Reserves

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

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

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

"Prepared" reserves are those estimates of quantities of reserves which were prepared by an independent petroleum consultant. "Audited" reserves are those quantities of revenues which were estimated by Devon employees and audited by an independent petroleum consultant.

The domestic reserves were evaluated by the independent petroleum consultants of LaRoche Petroleum Consultants, Ltd. and Ryder Scott Company, L.P. in each of the years presented. The Canadian reserves were evaluated by the independent petroleum consultants of AJM Petroleum Consultants in 2003 and 2002, and Paddock Lindstrom & Associates and Gilbert Laustsen Jung Associates, Ltd. in 2001. The International reserves were evaluated by the independent petroleum consultants of Ryder Scott Company, L.P. in each of the years presented.

Set forth below is a summary of the changes in the net quantities of crude oil, natural gas and natural gas liquids reserves for each of the three years ended December 31, 2003.

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

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

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

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

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

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

	International			
	Oil (MMBbls)	Gas (Bcf)	Natural Gas Liquids (MMBbls)	Total (MMBoe)
Proved reserves as of December 31, 2000	144	—	—	144
Revisions of estimates	11	—	—	11
Extensions and discoveries	—	—	—	—
Purchase of reserves	18	—	—	18
Production	(2)	—	—	(2)
Sale of reserves	(1)	—	—	(1)
Proved reserves as of December 31, 2001	170	—	—	170
Revisions of estimates	(20)	—	—	(20)
Extensions and discoveries	—	—	—	—
Purchase of reserves	—	—	—	—
Production	(2)	—	—	(2)
Sale of reserves	—	—	—	—
Proved reserves as of December 31, 2002	148	—	—	148
Revisions of estimates	1	(33)	—	(4)
Extensions and discoveries	1	—	—	1
Purchase of reserves	168	175	—	197
Production	(17)	(7)	—	(19)
Sale of reserves	—	—	—	—
Proved reserves as of December 31, 2003	301	135	—	323
Proved developed reserves as of:				
December 31, 2000	10	—	—	10
December 31, 2001	7	—	—	7
December 31, 2002	6	—	—	6
December 31, 2003	114	81	—	127

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

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

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

	Oil (MMBbls)	Gas (Bcf)	Natural Gas Liquids (MMBbls)	Total (MMBoe)
Proved reserves as of:				
December 31, 2000	53	413	12	134
December 31, 2001	59	453	13	147
December 31, 2002	1	—	—	1
Proved developed reserves as of:				
December 31, 2000	29	35	—	35
December 31, 2001	26	37	—	32
December 31, 2002	—	—	—	—

Standardized Measure of Discounted Future Net Cash Flows

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

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

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

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

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

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

Future cash inflows are computed by applying year-end prices (averaging $27.55 per barrel of oil, adjusted for transportation and other charges, $5.18 per Mcf of gas and $21.22 per barrel of natural gas liquids at December 31, 2003) to the year-end quantities of proved reserves, except in those instances where fixed and determinable price changes are provided by contractual arrangements in existence at year-end.

Future development and production costs are computed by estimating the expenditures to be incurred in developing and producing proved oil and gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions. Of the $3.7 billion of future development costs, $779 million, $596 million and $285 million are estimated to be spent in 2004, 2005 and 2006, respectively.

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

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

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

The preceding Total and International standardized measure of discounted future net cash flows tables exclude $21 million and $299 million in 2002 and 2001, respectively, related to discontinued operations.

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

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

	Year Ended December 31,		
	2003	2002	2001
		(In millions)	
Beginning balance	$10,365	5,015	12,065
Sales of oil, gas and natural gas liquids, net of production costs	(4,562)	(2,402)	(2,126)
Net changes in prices and production costs	2,645	9,122	(11,878)
Extensions, discoveries, and improved recovery, net of future development costs	2,218	1,471	582
Purchase of reserves, net of future development costs	5,763	888	2,480
Development costs incurred during the period which reduced future development costs	1,022	175	314
Revisions of quantity estimates	(728)	(61)	(316)
Sales of reserves in place	(307)	(1,879)	(84)
Accretion of discount	1,531	692	1,708
Net change in income taxes	(2,305)	(2,673)	3,340
Other, primarily changes in timing	279	17	(1,070)
Ending balance	$15,921	10,365	5,015

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

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

19. Supplemental Quarterly Financial Information (Unaudited)

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

	2003				
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Full Year
	(In millions, except per share amounts)				
Oil, gas and natural gas liquids sales	$1,237	1,478	1,613	1,564	5,892
Total revenues	$1,671	1,813	1,948	1,921	7,352
Net earnings before cumulative effect of change in accounting principle	$ 420	356	412	543	1,731
Net earnings	$ 436	356	412	543	1,747
Net earnings per common share:					
Basic:					
Net earnings before cumulative effect of change in accounting principle	$ 2.66	1.67	1.76	2.32	8.24
Cumulative effect of change in accounting principle	0.10	—	—	—	0.08
Total basic	$ 2.76	1.67	1.76	2.32	8.32
Diluted:					
Net earnings before cumulative effect of change in accounting principle	$ 2.57	1.62	1.71	2.25	8.00
Cumulative effect of change in accounting principle	0.10	—	—	—	0.07
Total diluted	$ 2.67	1.62	1.71	2.25	8.07

	2002				
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Full Year
	(In millions, except per share amounts)				
Oil, gas and natural gas liquids sales	$ 743	882	766	926	3,317
Total revenues	$ 903	1,149	1,031	1,233	4,316
Net earnings (loss)	$ 62	(104)	62	84	104
Net earnings (loss) per common share:					
Basic	$0.41	(0.68)	0.38	0.52	0.61
Diluted	$0.40	(0.68)	0.37	0.52	0.61

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

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

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

Item 9. ***Changes in and Disagreements with Accountants on Accounting and Financial Disclosure***

Not Applicable.

Item 9A. ***Controls and Procedures***

We maintain disclosure controls and procedures designed to ensure that information required to be disclosed in our filings under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's rules and forms. Our principal executive and financial officers have evaluated our disclosure controls and procedures and have determined that such disclosure controls and procedures were effective as of the end of the period covered by this Annual Report on Form 10-K.

PART III

Item 10. ***Directors and Executive Officers of the Registrant***

The information called for by this Item 10 is incorporated hereby by reference to the definitive Proxy Statement to be filed by Devon pursuant to Regulation 14A of the General Rules and Regulations under the Securities and Exchange Act of 1934 not later than April 29, 2004.

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 Devon pursuant to Regulation 14A of the General Rules and Regulations under the Securities and Exchange Act of 1934 not later than April 29, 2004.

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 Devon pursuant to Regulation 14A of the General Rules and Regulations under the Securities and Exchange Act of 1934 not later than April 29, 2004.

Item 13. ***Certain Relationships and Related Transactions***

None.

Item 14. ***Principal Auditor Fees and Services***

The information called for by this Item 14 is incorporated herein by reference to the definitive Proxy Statement to be filed by Devon pursuant to Regulation 14A of the General Rules and Regulations under the Securities and Exchange Act of 1934 not later than April 29, 2004.

PART IV

Item 15. ***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 in 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

Exhibit No.	Description
2.1	Agreement and Plan of Merger, dated as of February 23, 2003, by and among Registrant, Devon NewCo Corporation, and Ocean Energy, Inc. (incorporated by reference to Registrant's Amendment No. 1 to Form S-4 Registration No. 333-103679, filed March 20, 2003).
2.2	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),
2.3	Offer to Purchase for Cash and Directors' Circular dated September 6, 2001 (incorporated by reference to registrant's and Devon Acquisition Corporation's Schedule 14D-1F filing, filed September 6, 2001).
2.4	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).
2.5	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	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).
2.7	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).
2.8	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.
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 No.	Description
4.1	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).
4.2	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).
4.3	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).
4.4	Amendment to Rights Agreement, dated September 13, 2002, between Registrant and Wachovia Bank, N.A (incorporated by reference to Exhibit 4.9 to Registrant's Registration Statement on Form S-3 File Nos. 333-83156, 333-83156-1, and 333-83156-2 as filed on October 4, 2002).
4.5	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).
4.6	Indenture, dated as of March 1, 2002, between Registrant and The Bank of New York, as Trustee, relating to senior debt securities issuable by Registrant (the "Senior Indenture") (incorporated by reference to Exhibit 4.1 of Registrant's Form 8-K filed April 9, 2002).
4.7	Supplemental Indenture No. 1, dated as of March 25, 2002, between Registrant and The Bank of New York, as Trustee, relating to the 7.95% Senior Debentures due 2032 (incorporated by reference to Exhibit 4.2 to Registrant's Form 8-K filed on April 9, 2002).
4.8	Supplemental Indenture No. 2, dated as of August 4, 2003, between Registrant and The Bank of New York, as Trustee, relating to the 2.75% Senior Notes due 2006.
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), relating to the 6.875% Senior Notes due 2011 (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).
4.9	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), relating to the 7.875% Debentures due 2021 (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	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).
4.11	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).
4.12	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).
4.13	Second Supplemental Indenture, dated as of October 31, 2002, by and between Devon Energy Production Company, L.P., as Successor to the Issuer, and the Bank of New York, as Trustee, supplementing the Indenture dated as of June 1, 1999, as supplemented by the First Supplemental Indenture, dated as of June 14, 1999, by and between Devon SFS Operating, Inc. and the Trustee relating to Santa Fe Snyder Corporation's 8.05% Senior Notes due 2004 (incorporated by reference to Exhibit 4.1 of Registrant's Form 10-Q filed November 14, 2002).

Exhibit No.	Description
4.14	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 relating to 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)).
4.15	First Supplemental Indenture dated as of January 13, 1993 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 (incorporated by reference to Exhibit 4(p) to Pennzoil Company's Form 10-K for the year ended December 31, 1992).
4.16	Second Supplemental Indenture dated as of October 12, 1993 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 (incorporated by reference to Exhibit 4(i) to Pennzoil Company's Form 10-K for the year ended December 31, 1993).
4.17	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).
4.18	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).
4.19	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).
4.20	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).
4.21	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).
4.22	Purchase Agreement dated as of September 17, 2002 relating to the 4.375% Senior Notes due October 1, 2007 by and among Ocean Energy, Inc. and the underwriters named therein (incorporated by reference to Exhibit 1.1 to Ocean Energy, Inc.'s Current Report on Form 8-K filed with the SEC on September 17, 2002). Officers' Certificate evidencing the terms of the 4.375% Senior Notes due 2007, including the form of global note relating thereto (incorporated by reference to Exhibit 4.1 to Ocean Energy, Inc.'s Current Report on Form 8-K filed with the SEC on September 17, 2002).

Exhibit No.	Description
4.23	Senior Indenture dated as of September 28, 2001 between Ocean Energy, Inc. (a Louisiana corporation) and The Bank of New York, as trustee (incorporated by reference to Exhibit 4.1 to Ocean Energy, Inc.'s Current Report on Form 8-K filed with the SEC on September 28, 2001). Officer's Certificate establishing the terms of the 7.25% Senior Notes due 2011, including the form of global note relating thereto (incorporated by reference to Exhibit 4.2 to Ocean Energy, Inc.'s Current Report on Form 8-K filed with the SEC on September 28, 2001).
4.24	Indenture dated as of July 8, 1998 among Ocean Energy, Inc., its Subsidiary Guarantors, and Wells Fargo Bank Minnesota, N.A. as Trustee, relating to the 7.625% Senior Notes due 2005 (incorporated by reference to Exhibit 10.23 to the Form 10-Q for the period ended June 30, 1998 of Ocean Energy, Inc. (Registration No. 0-25058)).
4.25	First Supplemental Indenture, dated March 30, 1999 to indenture dated as of July 8, 1998 among Ocean Energy, Inc., its Subsidiary Guarantors, and Wells Fargo Bank Minnesota, N.A. as Trustee, relating to the 7.625% Senior Notes due 2005 (incorporated by reference to Exhibit 4.4 to the Company's Form 10-Q for the period ended March 31, 1999).
4.26	Second Supplemental Indenture, dated as of May 9, 2001 to indenture dated as of July 8, 1998 among Ocean Energy, Inc., its Subsidiary Guarantors, and Wells Fargo Bank Minnesota, N.A. as Trustee, relating to the 7.625% Senior Notes due 2005 (incorporated by reference to Exhibit 99.1 to Ocean Energy, Inc.'s Current Report on Form 8-K filed with the SEC on May 14, 2001).
4.27	Indenture dated as of July 8, 1998 among Ocean Energy, Inc., its Subsidiary Guarantors, and Wells Fargo Bank Minnesota, N.A., as Trustee, relating to the 8.25% Senior Notes due 2018 (incorporated by reference to Exhibit 10.24 to the Form 10-Q for the period ended June 30, 1998 of Ocean Energy, Inc. (Registration No. 0-25058).
4.28	First Supplemental Indenture, dated March 30, 1999 to indenture dated as of July 8, 1998 among Ocean Energy, Inc., its Subsidiary Guarantors, and Wells Fargo Bank Minnesota, N.A., as Trustee, relating to the 8.25% Senior Notes due 2018 (incorporated by reference to Exhibit 4.5 to Ocean Energy, Inc.'s Form 10-Q for the period ended March 31, 1999).
4.29	Second Supplemental Indenture, dated as of May 9, 2001 to indenture dated as of July 8, 1998 among Ocean Energy, Inc., its Subsidiary Guarantors, and Wells Fargo Bank Minnesota, N.A., as Trustee, relating to the 8.25% Senior Notes due 2018 (incorporated by reference to Exhibit 99.2 to Ocean Energy, Inc.'s Current Report on Form 8-K filed with the SEC on May 14, 2001).
4.30	Senior Indenture among Ocean Energy, Inc. and The Bank of New York, as Trustee, and Specimen of 7.50% Senior Notes (incorporated by reference to Exhibit 4.4 to Annual Report on Form 10-K for the year ended December 31, 1997).
4.31	First Supplemental Indenture, dated as of March 30, 1999 to Senior Indenture among Ocean Energy, Inc. and The Bank of New York, as Trustee, and Specimen of 7.50% Senior Notes (incorporated by reference to Exhibit 4.10 to the Company's Form 10-Q for the period ended March 31, 1999).
4.32	Second Supplemental Indenture, dated as of May 9, 2001 to Senior Indenture among Ocean Energy, Inc. and The Bank of New York, as Trustee, and Specimen of 7.50% Senior Notes (incorporated by reference to Exhibit 99.4 to Ocean Energy, Inc.'s Current Report on Form 8-K filed with the SEC on May 14, 2001).
4.33	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).
4.34	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).
4.35	Exchangeable Share Provisions (incorporated by reference to Exhibit 4.2 to Registrant's Form 8-K filed December 23,1998).

Exhibit No.	Description
4.36	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 Investor Rights Agreement, dated as of August 13, 2001, by and among Registrant, 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).
10.2	Credit Agreement dated July 25, 2002, by and among Northstar Energy Corporation and Devon Canada Corporation, as Borrowers and RBC Capital Markets, as Arranger and Royal Bank of Canada, as Administrative Agent and Certain Financial Institutions, as Lenders for the Cdn. $140 million credit facility (incorporated by reference to Exhibit 10.3 to Registrant's Form 10-Q filed on August 13, 2002).
10.3	Amended and Restated Canadian Credit Agreement dated June 7, 2002 among Northstar Energy Corporation and Devon Canada Corporation, as Canadian Borrowers, Bank of America, N.A. acting through its Canadian Branch, as Administrative Agent, and Certain Financial Institutions, as Lenders (incorporated by reference to Registrant's Form 10-Q filed on August 13, 2002).
10.4	First Amendment to Amended and Restated Canadian Credit Agreement dated June 5, 2003 among Northstar Energy Corporation and Devon Canada Corporation, as Canadian Borrowers, Bank of America, N.A. acting through its Canadian Branch, as Administrative Agent, and Certain Financial Institutions, as Lenders (incorporated by reference to Registrant's Form 10-Q filed on August 13, 2003).
10.5	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).
10.6	Amended and Restated U.S. Credit Agreement dated June 7, 2002 by and among Registrant, Bank of America, N.A., individually and as administrative agent, and the U.S. Lenders party to this Amendment (incorporated by reference to Registrant's Form 10-Q filed on August 13, 2002).
10.7	First Amendment to Amended and Restated U.S. Credit Agreement dated June 5, 2003 by and among Registrant, Bank of America, N.A., individually and as administrative agent, and the U.S. Lenders party to this Amendment (incorporated by reference to Registrant's Form 10-Q filed on August 13, 2003).
10.8	Credit Agreement, dated as of October 12, 2001, by and among Registrant, 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).
10.9	Amendment No. 1 to the Credit Agreement dated as of May 30, 2003, by and among Registrant, Devon Financing Corporation, U.L.C., UBS AG, Stamford Branch (as Administrative Agent), and the lenders signatory thereto (incorporated by reference to Registrant's Form 10-Q filed on August 13, 2003).

Exhibit No.	Description
10.10	Devon Energy Corporation Restricted Stock Bonus Plan (incorporated by reference to Registrant's Form S-8 filed on August 29, 2000, File No. 333-44702).*
10.11	Mitchell Energy & Development Corp. 1997 Bonus Unit Plan (incorporated by reference to Exhibit 10(e) to Mitchell Energy & Development Corp.'s Annual Report on Form 10-K for the year ended January 31, 1998).*
10.12	First Amendment to Mitchell Energy & Development Corp. 1997 Bonus Unit Plan (incorporated by reference to exhibit 10(c) of the Mitchell Energy & Development Corp. annual report on Form 10-K dated January 31, 1999).*
10.13	Mitchell Energy & Development Corp. 1999 Stock Option Plan (incorporated by reference to exhibit 10(d) of the annual report on Form 10-K dated January 31, 2000).*
10.14	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).*
10.15	PennzEnergy Company 1998 Incentive Plan (incorporated by reference to Exhibit 4.3 to Pennzoil Company's Form S-8 filed on December 29, 1998 SEC No. 333-69845).*
10.16	Pennzoil Company 1998 Stock Option Plan (incorporated by reference to SEC File No. 333-59011).*
10.17	Santa Fe Energy Resources Incentive Compensation Plan, as amended (incorporated by reference to exhibit 10(a) to Santa Fe Energy Resources, Inc.'s Annual Report on Form 10-K for the year ended December 31, 1998).*
10.18	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).*
10.19	Pennzoil Company 1997 Incentive Plan (incorporated by reference to Exhibit A to Pennzoil Company definitive proxy material filed on March 21, 1997, SEC File No. 1-5591).*
10.20	Pennzoil Company 1997 Stock Option Plan (incorporated by reference to SEC File No. 333-26021).*
10.21	Mitchell Energy & Development Corp. 1995 Stock Option Plan (incorporated by reference to SEC File No. 333-06981).*
10.22	Santa Fe Energy Resources, Inc. 1995 Incentive Stock Compensation Plan for Nonexecutive Officers (incorporated by reference to SEC File No. 033-59255).*
10.23	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).*
10.24	Santa Fe Energy Resources Deferred Compensation Plan, effective as of January 1, 1991, as amended and restated, effective February 1, 1994 (incorporated by reference to Exhibit 10(p) to Santa Fe Energy Resources, Inc.'s Annual Report on Form 10-K for the year ended December 31, 1993).*
10.25	Pennzoil Company 1990 Stock Option Plan (incorporated by reference to Pennzoil Company's definitive proxy material filed on April 26, 1990, File No. 1-5591).*
10.26	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).*
10.27	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).*
10.28	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).*

Exhibit No.	Description
10.29	Form of Employment Agreement between Registrant and Brian J. Jennings, J. Michael Lacey, Duke R. Ligon, Marian J. Moon, J. Larry Nichols, John Richels, Darryl G. Smette and William T. Vaughn, dated January 1, 2002. (incorporated by reference to Exhibit 10.26 of Registrant's Form 10-K for the year ended December 31, 2001).*
10.30	Devon Energy Corporation 2003 Long-Term Incentive Plan (incorporated by reference to Registrant's Form S-8 Registration No. 333-104922, filed May 1, 2003).
10.31	Global Natural Resources Inc. 1989 Key Employee Stock Option Plan (incorporated by reference to Registrant's Post Effective Amendment No. 1 to Form S-4 on Form S-8 Registration No. 333-103679, filed April 28, 2003).
10.32	Global Natural Resources Inc. 1992 Stock Option Plan (incorporated by reference to Registrant's Post Effective Amendment No. 1 to Form S-4 on Form S-8 Registration No. 333-103679, filed April 28, 2003).
10.33	Ocean Energy, Inc. Long Term Incentive Plan for Non-Executive Employees (incorporated by reference to Registrant's Post Effective Amendment No. 1 to Form S-4 on Form S-8 Registration No. 333-103679, filed April 28, 2003).
10.34	Ocean Energy, Inc. 1994 Long Term Incentive Plan (incorporated by reference to Registrant's Post Effective Amendment No. 1 to Form S-4 on Form S-8 Registration No. 333-103679, filed April 28, 2003).
10.35	Ocean Energy, Inc. 1996 Long Term Incentive Plan (incorporated by reference to Registrant's Post Effective Amendment No. 1 to Form S-4 on Form S-8 Registration No. 333-103679, filed April 28, 2003).
10.36	Ocean Energy, Inc. 1998 Long Term Incentive Plan (incorporated by reference to Registrant's Post Effective Amendment No. 1 to Form S-4 on Form S-8 Registration No. 333-103679, filed April 28, 2003).
10.37	Ocean Energy, Inc. 1999 Long Term Incentive Plan (incorporated by reference to Registrant's Post Effective Amendment No. 1 to Form S-4 on Form S-8 Registration No. 333-103679, filed April 28, 2003).
10.38	Ocean Energy, Inc. 2001 Long Term Incentive Plan (incorporated by reference to Registrant's Post Effective Amendment No. 1 to Form S-4 on Form S-8 Registration No. 333-103679, filed April 28, 2003).
10.39	Ocean Energy, Inc. Retirement Savings Plan (incorporated by reference to Registrant's Form S-8 Registration No. 333-104933, filed May 2, 2003)
10.40	Seagull Energy Corporation 1990 Stock Option Plan (incorporated by reference to Registrant's Form 10-K for the year ended December 31, 2002).
10.41	Seagull Energy Corporation 1993 Non-Employee Directors' Stock Option Plan (incorporated by reference to Registrant's Post Effective Amendment No. 1 to Form S-4 on Form S-8 Registration No. 333-103679, filed April 28, 2003).
10.42	Seagull Energy Corporation 1993 Stock Option Plan (incorporated by reference to Registrant's Post Effective Amendment No. 1 to Form S-4 on Form S-8 Registration No. 333-103679, filed April 28, 2003).
10.43	Seagull Energy Corporation 1995 Omnibus Stock Plan (incorporated by reference to Registrant's Post Effective Amendment No. 1 to Form S-4 on Form S-8 Registration No. 333-103679, filed April 28, 2003).
10.44	Seagull Energy Corporation 1998 Omnibus Stock Option Plan (incorporated by reference to Registrant's Post Effective Amendment No. 1 to Form S-4 on Form S-8 Registration No. 333-103679, filed April 28, 2003).
10.45	United Meridian Corporation 1987 Nonqualified Stock Option Plan (incorporated by reference to Registrant's Post Effective Amendment No. 1 to Form S-4 on Form S-8 Registration No. 333-103679, filed April 28, 2003).

Exhibit No.	Description
10.46	United Meridian Corporation 1994 Outside Director's Nonqualified Stock Option Plan (incorporated by reference to Registrant's Post Effective Amendment No. 1 to Form S-4 on Form S-8 Registration No. 333-103679, filed April 28, 2003).
10.47	United Meridian Corporation 1994 Employee Nonqualified Stock Option Plan (incorporated by reference to Registrant's Post Effective Amendment No. 1 to Form S-4 on Form S-8 Registration No. 333-103679, filed April 28, 2003).
12	Statement of computations of ratios of earnings to fixed charges and to combined fixed charges and preferred stock dividends.
21	List of Significant Subsidiaries of Registrant (incorporated by reference to Registrant's Form 10-K for the year ended December 31, 2002).
23.1	Consent of KPMG LLP
23.2	Consent of LaRoche Petroleum Consultants
23.3	Consent of Paddock Lindstrom & Associates Ltd.
23.4	Consent of Ryder Scott Company, L.P.
23.5	Consent of Gilbert Laustsen Jung Associates Ltd.
23.6	Consent of AJM Petroleum Consultants
31.1	Certification of J. Larry Nichols, Chief Executive Officer of Registrant, pursuant to Rule 13a-15(e) and 15d-15(e), as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2	Certification of William T. Vaughn, Chief Financial Officer of Registrant, pursuant to Rule 13a-15(e) and 15d-15(e), as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1	Certification of J. Larry Nichols, Chief Executive Officer of Registrant, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2	Certification of William T. Vaughn, Chief Financial Officer of Registrant, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

* Compensatory plans or arrangements

(b) *Reports on Form 8-K:*

On November 6, 2003, Devon reported Third Quarter Earnings.

On December 3, 2003, Devon announced the resignation of James T. Hackett.

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

By: /s/ J. LARRY NICHOLS

J. Larry Nichols,
Chairman of the Board and
Chief Executive Officer

March 4, 2004

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.

/s/ J. LARRY NICHOLS J. Larry Nichols	Chairman of the Board, Chief Executive Officer and Director	March 4, 2004
/s/ JOHN RICHELS John Richels	President	March 4, 2004
/s/ WILLIAM T. VAUGHN William T. Vaughn	Senior Vice President — Finance and Chief Financial Officer	March 4, 2004
/s/ DANNY J. HEATLY Danny J. Heatly	Vice President — Accounting	March 4, 2004
/s/ MILTON CARROLL Milton Carroll	Director	March 4, 2004
/s/ THOMAS F. FERGUSON Thomas F. Ferguson	Director	March 4, 2004
/s/ PETER J. FLUOR Peter J. Fluor	Director	March 4, 2004
/s/ DAVID M. GAVRIN David M. Gavrin	Director	March 4, 2004
/s/ MICHAEL E. GELLERT Michael E. Gellert	Director	March 4, 2004
/s/ JOHN A. HILL John A. Hill	Director	March 4, 2004

/s/ ROBERT L. HOWARD Robert L. Howard	Director	March 4, 2004
/s/ WILLIAM J. JOHNSON William J. Johnson	Director	March 4, 2004
/s/ MICHAEL M. KANOVSKY Michael M. Kanovsky	Director	March 4, 2004
/s/ CHARLES F. MITCHELL Charles F. Mitchell	Director	March 4, 2004
/s/ J. TODD MITCHELL J. Todd Mitchell	Director	March 4, 2004
/s/ ROBERT A. MOSBACHER, JR. Robert A. Mosbacher, Jr.	Director	March 4, 2004

INDEX TO EXHIBITS

Exhibit No.	Description
2.1	Agreement and Plan of Merger, dated as of February 23, 2003, by and among Registrant, Devon NewCo Corporation, and Ocean Energy, Inc. (incorporated by reference to Registrant's Amendment No. 1 to Form S-4 Registration No. 333-103679, filed March 20, 2003).
2.2	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),
2.3	Offer to Purchase for Cash and Directors' Circular dated September 6, 2001 (incorporated by reference to registrant's and Devon Acquisition Corporation's Schedule 14D-1F filing, filed September 6, 2001).
2.4	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).
2.5	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	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).
2.7	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).
2.8	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.
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	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).
4.2	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).
4.3	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).
4.4	Amendment to Rights Agreement, dated September 13, 2002, between Registrant and Wachovia Bank, N.A. (incorporated by reference to Exhibit 4.9 to Registrant's Registration Statement on Form S-3 File Nos. 333-83156, 333-83156-1, and 333-83156-2 as filed on October 4, 2002).
4.5	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).
4.6	Indenture, dated as of March 1, 2002, between Registrant and The Bank of New York, as Trustee, relating to senior debt securities issuable by Registrant (the "Senior Indenture") (incorporated by reference to Exhibit 4.1 of Registrant's Form 8-K filed April 9, 2002).

Exhibit No.	Description
4.7	Supplemental Indenture No. 1, dated as of March 25, 2002, between Registrant and The Bank of New York, as Trustee, relating to the 7.95% Senior Debentures due 2032 (incorporated by reference to Exhibit 4.2 to Registrant's Form 8-K filed on April 9, 2002).
4.8	Supplemental Indenture No. 2, dated as of August 4, 2003, between Registrant and The Bank of New York, as Trustee, relating to the 2.75% Senior Notes due 2006.
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), relating to the 6.875% Senior Notes due 2011 (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).
4.9	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), relating to the 7.875% Debentures due 2021 (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	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).
4.11	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).
4.12	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).
4.13	Second Supplemental Indenture, dated as of October 31, 2002, by and between Devon Energy Production Company, L.P., as Successor to the Issuer, and the Bank of New York, as Trustee, supplementing the Indenture dated as of June 1, 1999, as supplemented by the First Supplemental Indenture, dated as of June 14, 1999, by and between Devon SFS Operating, Inc. and the Trustee relating to Santa Fe Snyder Corporation's 8.05% Senior Notes due 2004 (incorporated by reference to Exhibit 4.1 of Registrant's Form 10-Q filed November 14, 2002).
4.14	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 relating to 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)).
4.15	First Supplemental Indenture dated as of January 13, 1993 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 (incorporated by reference to Exhibit 4(p) to Pennzoil Company's Form 10-K for the year ended December 31, 1992).
4.16	Second Supplemental Indenture dated as of October 12, 1993 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 (incorporated by reference to Exhibit 4(i) to Pennzoil Company's Form 10-K for the year ended December 31, 1993).
4.17	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).
4.18	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).

Exhibit No.	Description
4.19	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).
4.20	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).
4.21	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).
4.22	Purchase Agreement dated as of September 17, 2002 relating to the 4.375% Senior Notes due October 1, 2007 by and among Ocean Energy, Inc. and the underwriters named therein (incorporated by reference to Exhibit 1.1 to Ocean Energy, Inc.'s Current Report on Form 8-K filed with the SEC on September 17, 2002). Officers' Certificate evidencing the terms of the 4.375% Senior Notes due 2007, including the form of global note relating thereto (incorporated by reference to Exhibit 4.1 to Ocean Energy, Inc.'s Current Report on Form 8-K filed with the SEC on September 17, 2002).
4.23	Senior Indenture dated as of September 28, 2001 between Ocean Energy, Inc. (a Louisiana corporation) and The Bank of New York, as trustee (incorporated by reference to Exhibit 4.1 to Ocean Energy, Inc.'s Current Report on Form 8-K filed with the SEC on September 28, 2001). Officer's Certificate establishing the terms of the 7.25% Senior Notes due 2011, including the form of global note relating thereto (incorporated by reference to Exhibit 4.2 to Ocean Energy, Inc.'s Current Report on Form 8-K filed with the SEC on September 28, 2001).
4.24	Indenture dated as of July 8, 1998 among Ocean Energy, Inc., its Subsidiary Guarantors, and Wells Fargo Bank Minnesota, N.A. as Trustee, relating to the 7.625% Senior Notes due 2005 (incorporated by reference to Exhibit 10.23 to the Form 10-Q for the period ended June 30, 1998 of Ocean Energy, Inc. (Registration No. 0-25058)).
4.25	First Supplemental Indenture, dated March 30, 1999 to indenture dated as of July 8, 1998 among Ocean Energy, Inc., its Subsidiary Guarantors, and Wells Fargo Bank Minnesota, N.A. as Trustee, relating to the 7.625% Senior Notes due 2005 (incorporated by reference to Exhibit 4.4 to the Company's Form 10-Q for the period ended March 31, 1999).
4.26	Second Supplemental Indenture, dated as of May 9, 2001 to indenture dated as of July 8, 1998 among Ocean Energy, Inc., its Subsidiary Guarantors, and Wells Fargo Bank Minnesota, N.A. as Trustee, relating to the 7.625% Senior Notes due 2005 (incorporated by reference to Exhibit 99.1 to Ocean Energy, Inc.'s Current Report on Form 8-K filed with the SEC on May 14, 2001).
4.27	Indenture dated as of July 8, 1998 among Ocean Energy, Inc., its Subsidiary Guarantors, and Wells Fargo Bank Minnesota, N.A., as Trustee, relating to the 8.25% Senior Notes due 2018 (incorporated by reference to Exhibit 10.24 to the Form 10-Q for the period ended June 30, 1998 of Ocean Energy, Inc. (Registration No. 0-25058).
4.28	First Supplemental Indenture, dated March 30, 1999 to indenture dated as of July 8, 1998 among Ocean Energy, Inc., its Subsidiary Guarantors, and Wells Fargo Bank Minnesota, N.A., as Trustee, relating to the 8.25% Senior Notes due 2018 (incorporated by reference to Exhibit 4.5 to Ocean Energy, Inc.'s Form 10-Q for the period ended March 31, 1999).
4.29	Second Supplemental Indenture, dated as of May 9, 2001 to indenture dated as of July 8, 1998 among Ocean Energy, Inc., its Subsidiary Guarantors, and Wells Fargo Bank Minnesota, N.A., as Trustee, relating to the 8.25% Senior Notes due 2018 (incorporated by reference to Exhibit 99.2 to Ocean Energy, Inc.'s Current Report on Form 8-K filed with the SEC on May 14, 2001).

Exhibit No.	Description
4.30	Senior Indenture among Ocean Energy, Inc. and The Bank of New York, as Trustee, and Specimen of 7.50% Senior Notes (incorporated by reference to Exhibit 4.4 to Annual Report on Form 10-K for the year ended December 31, 1997.
4.31	First Supplemental Indenture, dated as of March 30, 1999 to Senior Indenture among Ocean Energy, Inc. and The Bank of New York, as Trustee, and Specimen of 7.50% Senior Notes (incorporated by reference to Exhibit 4.10 to the Company's Form 10-Q for the period ended March 31, 1999).
4.32	Second Supplemental Indenture, dated as of May 9, 2001 to Senior Indenture among Ocean Energy, Inc. and The Bank of New York, as Trustee, and Specimen of 7.50% Senior Notes (incorporated by reference to Exhibit 99.4 to Ocean Energy, Inc.'s Current Report on Form 8-K filed with the SEC on May 14, 2001).
4.33	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).
4.34	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).
4.35	Exchangeable Share Provisions (incorporated by reference to Exhibit 4.2 to Registrant's Form 8-K filed December 23,1998).
4.36	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 Investor Rights Agreement, dated as of August 13, 2001, by and among Registrant, 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).
10.2	Credit Agreement dated July 25, 2002, by and among Northstar Energy Corporation and Devon Canada Corporation, as Borrowers and RBC Capital Markets, as Arranger and Royal Bank of Canada, as Administrative Agent and Certain Financial Institutions, as Lenders for the Cdn. $140 million credit facility (incorporated by reference to Exhibit 10.3 to Registrant's Form 10-Q filed on August 13, 2002).
10.3	Amended and Restated Canadian Credit Agreement dated June 7, 2002 among Northstar Energy Corporation and Devon Canada Corporation, as Canadian Borrowers, Bank of America, N.A. acting through its Canadian Branch, as Administrative Agent, and Certain Financial Institutions, as Lenders (incorporated by reference to Registrant's Form 10-Q filed on August 13, 2002).
10.4	First Amendment to Amended and Restated Canadian Credit Agreement dated June 5, 2003 among Northstar Energy Corporation and Devon Canada Corporation, as Canadian Borrowers, Bank of America, N.A. acting through its Canadian Branch, as Administrative Agent, and Certain Financial Institutions, as Lenders (incorporated by reference to Registrant's Form 10-Q filed on August 13, 2003).
10.5	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).

Exhibit No.	Description
10.6	Amended and Restated U.S. Credit Agreement dated June 7, 2002 by and among Registrant, Bank of America, N.A., individually and as administrative agent, and the U.S. Lenders party to this Amendment (incorporated by reference to Registrant's Form 10-Q filed on August 13, 2002).
10.7	First Amendment to Amended and Restated U.S. Credit Agreement dated June 5, 2003 by and among Registrant, Bank of America, N.A., individually and as administrative agent, and the U.S. Lenders party to this Amendment (incorporated by reference to Registrant's Form 10-Q filed on August 13, 2003).
10.8	Credit Agreement, dated as of October 12, 2001, by and among Registrant, 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).
10.9	Amendment No. 1 to the Credit Agreement dated as of May 30, 2003, by and among Registrant, Devon Financing Corporation, U.L.C., UBS AG, Stamford Branch (as Administrative Agent), and the lenders signatory thereto (incorporated by reference to Registrant's Form 10-Q filed on August 13, 2003).
10.10	Devon Energy Corporation Restricted Stock Bonus Plan (incorporated by reference to Registrant's Form S-8 filed on August 29, 2000, File No. 333-44702).*
10.11	Mitchell Energy & Development Corp. 1997 Bonus Unit Plan (incorporated by reference to Exhibit 10(e) to Mitchell Energy & Development Corp.'s Annual Report on Form 10-K for the year ended January 31, 1998).*
10.12	First Amendment to Mitchell Energy & Development Corp. 1997 Bonus Unit Plan (incorporated by reference to exhibit 10(c) of the Mitchell Energy & Development Corp. annual report on Form 10-K dated January 31, 1999).*
10.13	Mitchell Energy & Development Corp. 1999 Stock Option Plan (incorporated by reference to exhibit 10(d) of the annual report on Form 10-K dated January 31, 2000).*
10.14	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).*
10.15	PennzEnergy Company 1998 Incentive Plan (incorporated by reference to Exhibit 4.3 to Pennzoil Company's Form S-8 filed on December 29, 1998 SEC No. 333-69845).*
10.16	Pennzoil Company 1998 Stock Option Plan (incorporated by reference to SEC File No. 333-59011).*
10.17	Santa Fe Energy Resources Incentive Compensation Plan, as amended (incorporated by reference to exhibit 10(a) to Santa Fe Energy Resources, Inc.'s Annual Report on Form 10-K for the year ended December 31, 1998).*
10.18	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).*
10.19	Pennzoil Company 1997 Incentive Plan (incorporated by reference to Exhibit A to Pennzoil Company definitive proxy material filed on March 21, 1997, SEC File No. 1-5591).*
10.20	Pennzoil Company 1997 Stock Option Plan (incorporated by reference to SEC File No. 333-26021).*
10.21	Mitchell Energy & Development Corp. 1995 Stock Option Plan (incorporated by reference to SEC File No. 333-06981).*
10.22	Santa Fe Energy Resources, Inc. 1995 Incentive Stock Compensation Plan for Nonexecutive Officers (incorporated by reference to SEC File No. 033-59255).*
10.23	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).*

Exhibit No.	Description
10.24	Santa Fe Energy Resources Deferred Compensation Plan, effective as of January 1, 1991, as amended and restated, effective February 1, 1994 (incorporated by reference to Exhibit 10(p) to Santa Fe Energy Resources, Inc.'s Annual Report on Form 10-K for the year ended December 31, 1993).*
10.25	Pennzoil Company 1990 Stock Option Plan (incorporated by reference to Pennzoil Company's definitive proxy material filed on April 26, 1990, File No. 1-5591).*
10.26	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).*
10.27	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).*
10.28	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).*
10.29	Form of Employment Agreement between Registrant and Brian J. Jennings, J. Michael Lacey, Duke R. Ligon, Marian J. Moon, J. Larry Nichols, John Richels, Darryl G. Smette and William T. Vaughn, dated January 1, 2002. (incorporated by reference to Exhibit 10.26 of Registrant's Form 10-K for the year ended December 31, 2001).*
10.30	Devon Energy Corporation 2003 Long-Term Incentive Plan (incorporated by reference to Registrant's Form S-8 Registration No. 333-104922, filed May 1, 2003).
10.31	Global Natural Resources Inc. 1989 Key Employee Stock Option Plan (incorporated by reference to Registrant's Post Effective Amendment No. 1 to Form S-4 on Form S-8 Registration No. 333-103679, filed April 28, 2003).
10.32	Global Natural Resources Inc. 1992 Stock Option Plan (incorporated by reference to Registrant's Post Effective Amendment No. 1 to Form S-4 on Form S-8 Registration No. 333-103679, filed April 28, 2003).
10.33	Ocean Energy, Inc. Long Term Incentive Plan for Non-Executive Employees (incorporated by reference to Registrant's Post Effective Amendment No. 1 to Form S-4 on Form S-8 Registration No. 333-103679, filed April 28, 2003).
10.34	Ocean Energy, Inc. 1994 Long Term Incentive Plan (incorporated by reference to Registrant's Post Effective Amendment No. 1 to Form S-4 on Form S-8 Registration No. 333-103679, filed April 28, 2003).
10.35	Ocean Energy, Inc. 1996 Long Term Incentive Plan (incorporated by reference to Registrant's Post Effective Amendment No. 1 to Form S-4 on Form S-8 Registration No. 333-103679, filed April 28, 2003).
10.36	Ocean Energy, Inc. 1998 Long Term Incentive Plan (incorporated by reference to Registrant's Post Effective Amendment No. 1 to Form S-4 on Form S-8 Registration No. 333-103679, filed April 28, 2003).
10.37	Ocean Energy, Inc. 1999 Long Term Incentive Plan (incorporated by reference to Registrant's Post Effective Amendment No. 1 to Form S-4 on Form S-8 Registration No. 333-103679, filed April 28, 2003).
10.38	Ocean Energy, Inc. 2001 Long Term Incentive Plan (incorporated by reference to Registrant's Post Effective Amendment No. 1 to Form S-4 on Form S-8 Registration No. 333-103679, filed April 28, 2003).
10.39	Ocean Energy, Inc. Retirement Savings Plan (incorporated by reference to Registrant's Form S-8 Registration No. 333-104933, filed May 2, 2003)
10.40	Seagull Energy Corporation 1990 Stock Option Plan (incorporated by reference to Registrant's Form 10-K for the year ended December 31, 2002).
10.41	Seagull Energy Corporation 1993 Non-Employee Directors' Stock Option Plan (incorporated by reference to Registrant's Post Effective Amendment No. 1 to Form S-4 on Form S-8 Registration No. 333-103679, filed April 28, 2003).

Exhibit No.	Description
10.42	Seagull Energy Corporation 1993 Stock Option Plan (incorporated by reference to Registrant's Post Effective Amendment No. 1 to Form S-4 on Form S-8 Registration No. 333-103679, filed April 28, 2003).
10.43	Seagull Energy Corporation 1995 Omnibus Stock Plan (incorporated by reference to Registrant's Post Effective Amendment No. 1 to Form S-4 on Form S-8 Registration No. 333-103679, filed April 28, 2003).
10.44	Seagull Energy Corporation 1998 Omnibus Stock Option Plan (incorporated by reference to Registrant's Post Effective Amendment No. 1 to Form S-4 on Form S-8 Registration No. 333-103679, filed April 28, 2003).
10.45	United Meridian Corporation 1987 Nonqualified Stock Option Plan (incorporated by reference to Registrant's Post Effective Amendment No. 1 to Form S-4 on Form S-8 Registration No. 333-103679, filed April 28, 2003).
10.46	United Meridian Corporation 1994 Outside Director's Nonqualified Stock Option Plan (incorporated by reference to Registrant's Post Effective Amendment No. 1 to Form S-4 on Form S-8 Registration No. 333-103679, filed April 28, 2003).
10.47	United Meridian Corporation 1994 Employee Nonqualified Stock Option Plan (incorporated by reference to Registrant's Post Effective Amendment No. 1 to Form S-4 on Form S-8 Registration No. 333-103679, filed April 28, 2003).
12	Statement of computations of ratios of earnings to fixed charges and to combined fixed charges and preferred stock dividends.
21	List of Significant Subsidiaries of Registrant (incorporated by reference to Registrant's Form 10-K for the year ended December 31, 2002).
23.1	Consent of KPMG LLP
23.2	Consent of LaRoche Petroleum Consultants
23.3	Consent of Paddock Lindstrom & Associates Ltd.
23.4	Consent of Ryder Scott Company, L.P.
23.5	Consent of Gilbert Laustsen Jung Associates Ltd.
23.6	Consent of AJM Petroleum Consultants
31.1	Certification of J. Larry Nichols, Chief Executive Officer of Registrant, pursuant to Rule 13a-15(e) and 15d-15(e), as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2	Certification of William T. Vaughn, Chief Financial Officer of Registrant, pursuant to Rule 13a-15(e) and 15d-15(e), as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1	Certification of J. Larry Nichols, Chief Executive Officer of Registrant, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2	Certification of William T. Vaughn, Chief Financial Officer of Registrant, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

* Compensatory plans or arrangements

EXHIBIT 3.1

RESTATED CERTIFICATE OF INCORPORATION

OF

Devon Energy Corporation

(Originally incorporated under the name
"Devon Delaware Corporation" on May 18, 1999)

ARTICLE I

Name

The name of this corporation (the "Corporation") is Devon Energy Corporation.

ARTICLE II

Registered Office

The address of the registered office of the Corporation in the State of Delaware is at 2711 Centerville Road, Suite 400, City of Wilmington, County of New Castle 19808, and the name of its registered agent at that address is Corporation Service Company.

ARTICLE III

Business

The purpose of the Corporation is to engage in any lawful act or activity for which corporations may be organized under the General Corporation Law of the State of Delaware (the "General Corporation Law").

ARTICLE IV

Authorized Capital Stock

A. The Corporation shall be authorized to issue a total of 804,500,001 shares of capital stock divided into classes as follows:

(1) 800,000,000 shares of Common Stock, par value $0.10 per share ("Common Stock"),

(2) 4,500,000 shares of Preferred Stock, par value $1.00 per share ("Preferred Stock"), and

(3) one share of Special Voting Stock, par value $.10 per share.

B. Shares of Preferred Stock may be issued from time to time in one or more series as may from time to time be determined by the Board of Directors of the Corporation (the “Board”), each of said series to be distinctly designated. The voting powers, preferences and relative, participating, optional and other special rights, and the qualifications, limitations or restrictions thereof, if any, of each such series may differ from those of any and all other series of Preferred Stock at any time outstanding, and the Board is hereby expressly granted authority to fix or alter, by resolution or resolutions, the designation, number, voting powers, preferences and relative, participating, optional and other special rights, and the qualifications, limitations and restrictions thereof, of each such series, including, but without limiting the generality of the foregoing, the following:

(1) The distinctive designation of, and the number of shares of Preferred Stock that shall constitute, such series, which number (except where otherwise provided by the Board in the resolution establishing such series) may be increased or decreased (but not below the number of shares of such series then outstanding) from time to time by action of the Board;

(2) The rights in respect of dividends, if any, of such series of Preferred Stock, the extent of the preference or relation, if any, of such dividends to the dividends payable on any other class or classes or any other series of the same or other class or classes of capital stock of the Corporation, and whether or in what circumstances such dividends shall be cumulative;

(3) The right, if any, of the holders of such series of Preferred Stock to convert the same into, or exchange the same for, shares of any other class or classes or of any other series of the same or any other class or classes of capital stock or other securities of the Corporation or any other person, and the terms and conditions of such conversion or exchange;

(4) Whether or not shares of such series of Preferred Stock shall be subject to redemption, and, if so, the terms and conditions of such redemption (including whether such redemption shall be optional or mandatory), including the date or dates or event or events upon or after which they shall be redeemable, and the amount and type of consideration payable upon redemption, which may vary under different conditions and at different redemption dates;

(5) The rights, if any, of the holders of such series of Preferred Stock upon the voluntary or involuntary liquidation, dissolution or winding-up of the Corporation or in the event of any merger or consolidation of or sale of assets by the Corporation;

(6) The terms of any sinking fund or redemption or purchase account, if any, to be provided for shares of such series of the Preferred Stock;

(7) The voting powers, if any, of the holders of any series of Preferred Stock generally or with respect to any particular matter, which may be less than, equal to or greater than one vote per share, and which may, without limiting the generality of the foregoing, include the right, voting as a series by itself or together with the holders of any

other series of Preferred Stock or all series of Preferred Stock as a class, to elect one or more directors of the Corporation generally or under such specific circumstances and on such conditions, as shall be provided in the resolution or resolutions of the Board adopted pursuant hereto, including, without limitation, in the event there shall have been a default in the payment of dividends on or redemption of any one or more series of Preferred Stock; and

(8) Any other powers, preferences and relative, participating, optional or other rights, and qualifications, limitations or restrictions of shares of such series of Preferred Stock.

Pursuant to the authority conferred by this Article IV, the following series of Preferred Stock have been designated, each such series consisting of such number of shares, with such voting powers and with such designations, preferences and relative, participating, optional or other special rights, and qualifications, limitations or restrictions thereof as are stated and expressed in the exhibit with respect to such series attached hereto as specified below and incorporated herein by reference:

Exhibit A	6.49% Cumulative Preferred Stock, Series A
Exhibit B	Series A Junior Participating Preferred Stock
Exhibit C	Special Voting Preferred Stock

C. (1) After the provisions with respect to preferential dividends on any series of Preferred Stock (fixed in accordance with the provisions of Paragraph B of this Article IV), if any, shall have been satisfied and after the Corporation shall have complied with all the requirements, if any, with respect to redemption of, or the setting aside of sums as sinking funds or redemption or purchase accounts with respect to, any series of Preferred Stock (fixed in accordance with the provisions of Paragraph B of this Article IV), and subject further to any other conditions that may be fixed in accordance with the provisions of Paragraph B of this Article IV, then and not otherwise the holders of Common Stock shall be entitled to receive such dividends as may be declared from time to time by the Board.

(2) In the event of the voluntary or involuntary liquidation, dissolution or winding-up of the Corporation, after distribution in full of the preferential amounts, if any (fixed in accordance with the provisions of Paragraph B of this Article IV), to be distributed to the holders of Preferred Stock by reason thereof, the holders of Common Stock shall, subject to the additional rights, if any (fixed in accordance with the provisions of Paragraph B of this Article IV), of the holders of any outstanding shares of Preferred Stock, be entitled to receive all of the remaining assets of the Corporation, tangible and intangible, of whatever kind available for distribution to stockholders ratably in proportion to the number of shares of Common Stock held by them respectively.

(3) Except as may otherwise be required by law, and subject to the provisions of such resolution or resolutions as may be adopted by the Board pursuant to Paragraph B of this Article IV granting the holders of one or more series of Preferred Stock exclusive voting powers with respect to any matter, each holder of Common Stock shall have one vote in respect of each share of Common Stock held on all matters voted upon by the stockholders.

(4) The authorized amount of shares of Common Stock and of Preferred Stock may, without a class or series vote, be increased or decreased from time to time by the affirmative vote of the holders of a majority of the combined voting power of the then-outstanding shares of Voting Stock, voting together as a single class.

D. Each outstanding share of Special Voting Stock shall be entitled, on all matters presented to the stockholders of the Corporation, to that number of votes equal to the number of Exchangeable Shares of Northstar Energy Corporation, an Alberta corporation, outstanding from time to time not owned by the Corporation or any of its wholly owned subsidiaries. No dividend or distribution of assets shall be paid to the holders of Special Voting Stock. The Special Voting Stock is not convertible into any other class or series of the capital stock of the Corporation or into cash, property or other rights, and may not be redeemed. Any shares of Special Voting Stock purchased or otherwise acquired by the Corporation shall be deemed retired and shall be canceled and may not thereafter be reissued or otherwise disposed of by the Corporation. At such time as the Special Voting Stock has no votes attached to it because there are no Exchangeable Shares outstanding, the Special Voting Stock shall be canceled. In respect of all matters concerning the voting of shares, the Common Stock and the Special Voting Stock shall vote as a single class and such voting rights shall be identical in all respects.

E. No stockholder of the Corporation shall by reason of his holding shares of any class or series of stock of the Corporation have any preemptive or preferential right to purchase, acquire, subscribe for or otherwise receive any additional, unissued or treasury shares (whether now or hereafter acquired) of any class or series of stock of the Corporation now or hereafter to be authorized, or any notes, debentures, bonds or other securities convertible into or carrying any right, option or warrant to purchase, acquire, subscribe for or otherwise receive shares of any class or series of stock of the Corporation now or hereafter to be authorized, whether or not the issuance of any such shares, or such notes, debentures, bonds or other securities, would adversely affect the dividends or voting or other rights of such stockholder, and the Board may issue or authorize the issuance of shares of any class or series of stock of the Corporation, or any notes, debentures, bonds or other securities convertible into or carrying rights, options or warrants to purchase, acquire, subscribe for or otherwise receive shares of any class or series of stock of the Corporation, without offering any such shares of any such class, either in whole or in part, to the existing stockholders of any class.

F. Cumulative voting of shares of any class or series of capital stock of the Corporation having voting rights is not permitted.

G. The holders of Convertible Debentures (as hereinafter defined) shall have the right to convert such Convertible Debentures into Common Stock, subject to the terms of the Indenture (as hereinafter defined). Indenture means the Indenture, dated as of July 3, 1996, between Devon Energy Corporation and The Bank of New York, as the same may be supplemented or amended from time to time. “Convertible Debentures” has the meaning assigned to such term in the First Supplemental Indenture, dated as of July 3, 1999, between Devon Energy Corporation and the Bank of New York.

The Corporation shall make any further conversion adjustments as may be required from time to time by the Indenture and the Supplemental Indenture.

ARTICLE V

Election of Directors

A. The business and affairs of the Corporation shall be conducted and managed by, or under the direction of, the Board. The number of directors which shall constitute the entire Board shall not be less than three nor more than twenty, and, except as provided in Paragraph D of this Article V, shall be determined by resolution adopted by a majority of the entire Board. No reduction in number shall have the effect of removing any director prior to the expiration of his or her term.

B. The Board, other than those directors elected by the holders of any series of Preferred Stock as provided for or fixed pursuant to the provisions of Article IV, shall be divided into three classes, Class I, Class II and Class III, and the Board shall designate the directors who shall first serve in Class I, Class II and Class III. Such classes shall be as nearly equal in number as possible; provided, however, the Board of Directors at the time of filing the Certificate of Merger pursuant to the Amended and Restated Agreement and Plan of Merger, dated May 19, 1999, among the Corporation, Devon Energy Corporation, an Oklahoma corporation, Devon Oklahoma Corporation, an Oklahoma corporation, and PennzEnergy Company, a Delaware corporation, shall have four directors in Class I, four directors in Class II and six directors in Class III. Each director shall serve for a term ending on the third annual meeting following the annual meeting at which such director was elected; *provided, however* , that the directors first designated to Class I shall serve for a term expiring at the annual meeting next following the date of their designation as Class I Directors, the directors first designated to Class II shall serve for a term expiring at the second annual meeting next following the date of their designation as Class II Directors, and the directors first designated to Class III shall serve for a term expiring at the third annual meeting next following the date of their designation as Class III Directors. At each annual election of directors, the directors chosen to succeed those whose terms then expire shall be of the same class as the directors of the Corporation they succeed, unless the Board of Directors shall designate one or more directorships whose term then expires as directorships of another class in order more nearly to achieve equality of number of directors among the classes. In the event of any change in the authorized number of Directors of the Corporation, each Director of the Corporation then continuing to serve as such shall nevertheless continue as a Director of the class of which he is a member until the expiration of his current term, or his prior death, resignation or removal.

C. Except as otherwise provided for or fixed pursuant to the provisions of Article IV relating to the rights of the holders of any series of Preferred Stock to elect additional directors, except as provided in Paragraph D of this Article V, and subject to the provisions hereof, newly created directorships resulting from any increase in the authorized number of directors, and any vacancies on the Board resulting from death, resignation, disqualification, removal, or other cause, may be filled only by the affirmative vote of a majority of the remaining directors then in office, even though less than a quorum of the Board. Any director elected in accordance with the preceding sentence or Paragraph D of this Article V shall hold office for the remainder of the full

term of the class of directors in which the new directorship was created or in which the vacancy occurred, and until such director's successor shall have been duly elected and qualified, subject to his earlier death, disqualification, resignation or removal. Except as otherwise provided pursuant to Article IV of this Certificate of Incorporation relating to additional directors elected by the holders of one or more series of Preferred Stock, no decrease in the number of directors constituting the Board shall shorten the term of any incumbent director.

D. There shall be a "Balance Period" during which the number of directors constituting the whole Board shall at all times be an even number and vacancies and newly created directorships resulting from any increase in the authorized number of directors shall be filled, and nominations by the Board shall be made, as follows:

(a) Any vacancy on the Board resulting from the death, resignation, disqualification or removal of a Continuing Director (hereinafter defined) shall be filled only by the affirmative vote of a majority of the remaining Continuing Directors then in office. Nominations of the Board to fill the positions of Continuing Directors whose terms are about to expire shall likewise be made by the affirmative vote of a majority of the Continuing Directors then in office.

(b) Any vacancy on the Board resulting from the death, resignation, disqualification or removal of a New Director (hereinafter defined) shall be filled only by the affirmative vote of a majority of the remaining New Directors then in office. Nominations of the Board to fill the positions of New Directors whose terms are about to expire shall likewise be made by the affirmative vote of a majority of the New Directors then in office. Notwithstanding the foregoing provisions of this paragraph (b), throughout the Balance Period at least one New Director shall be a person who shall have been mutually approved (prior to his or her initial election to the Board) by the Chairman and the President of the Corporation.

(c) Any newly created directorship or directorships resulting from an increase in the authorized number of directors shall be allocated so that the aggregate number of board positions to be filled by Continuing Directors shall be equal to the number of Board positions to be filled by New Directors. Such newly created directorships to be filled by Continuing Directors shall be filled, or nominations therefor made, in the same manner as is provided in paragraph (a) above and such newly created directorships to be filled, or nominations therefor made, by New Directors shall be filled in the same manner as is provided in paragraph (b) above.

The number of directors which shall constitute the entire Board shall be expanded if necessary to comply with the foregoing provision of this Section D.

The Balance Period shall begin on the date this Amended and Restated Certificate of Incorporation becomes effective and shall end on the annual meeting of the stockholders in the year 2000.

“Continuing Director” shall mean a director who was a director of Devon Energy Corporation, an Oklahoma corporation, immediately prior to the Closing under the Amended and Restated Agreement and Plan of Merger by and among the Corporation, Devon Energy Corporation, Devon Oklahoma Corporation and PennzEnergy Company dated as of May 19, 1999, or who subsequently became a director as a result of the filing of a newly created directorship or vacancy by the Continuing Directors as aforesaid or as a result of his or her election as a director having been nominated by the Continuing Directors as herein provided. “New Director” shall mean any director other than a Continuing Director.

E. During any period when the holders of any series of Preferred Stock have the right to elect additional directors as provided for or fixed pursuant to the provisions of Article IV, then upon commencement and for the duration of the period during which such right continues (i) the then otherwise total authorized number of directors of the Corporation shall automatically be increased by such specified number of directors, and the holders of such Preferred Stock shall be entitled to elect the additional directors so provided for or fixed pursuant to said provisions, and (ii) each such additional director shall serve until such director’s successor shall have been duly elected and qualified, or until such director’s right to hold such office terminates pursuant to said provisions, whichever occurs earlier, subject to his earlier death, disqualification, resignation or removal. Except as otherwise provided by the Board in the resolution or resolutions establishing such series, whenever the holders of any series of Preferred Stock having such right to elect additional directors are divested of such right pursuant to the provisions of such stock, the terms of office of all such additional directors elected by the holders of such stock, or elected to fill any vacancies resulting from the death, resignation, disqualification or removal of such additional directors, shall forthwith terminate and the total and authorized number of directors of the Corporation shall be reduced accordingly.

ARTICLE VI

Meetings of Stockholders

A. Meetings of stockholders of the Corporation may be held within or without the State of Delaware, as the By-laws of the Corporation may provide. Except as otherwise provided for or fixed pursuant to the provisions of Article IV relating to the rights of the holders of any series of Preferred Stock, special meetings of stockholders of the Corporation may be called only (i) pursuant to a resolution adopted by a majority of the then-authorized number of directors of the Corporation and (ii) if permitted by the By-laws of the Corporation, by the Chairman of the Board or the President of the Corporation as and in the manner provided in the By-laws of the Corporation. Special meetings of stockholders may not be called by any other person or persons or in any other manner. The ability of the stockholders of the Corporation to call a special meeting of stockholders is hereby specifically denied. Elections of directors need not be by written ballot unless the By-laws of the Corporation shall so provide.

B. In addition to the powers conferred on the Board by this Certificate of Incorporation and by the General Corporation Law, and without limiting the generality thereof, the Board is specifically authorized from time to time, by resolution of the Board without additional authorization by the stockholders of the Corporation, to adopt, amend or repeal the By-laws of the Corporation, in such form and with such terms as the Board may determine,

including, without limiting the generality of the foregoing, By-laws relating to (i) regulation of the procedure for submission by stockholders of nominations of persons to be elected to the Board, (ii) regulation of the attendance at annual or special meetings of the stockholders of persons other than holders of record or their proxies, and (iii) regulation of the business that may properly be brought by a stockholder of the Corporation before an annual or special meeting of stockholders of the Corporation.

ARTICLE VII

Stockholder Consent

Any action required or permitted to be taken by the stockholders of the Corporation must be effected at a duly called annual or special meeting of stockholders of the Corporation, and the ability of the stockholders of the Corporation to consent in writing to the taking of any action is hereby specifically denied.

ARTICLE VIII

Limitation of Liability

A director of this Corporation shall not be liable to the Corporation or its stockholders for monetary damages for breach of fiduciary duty as a director, except to the extent such exemption from liability or limitation thereof is not permitted under the General Corporation Law as the same exists or may hereafter be amended. Any repeal or modification of the foregoing paragraph shall not adversely affect any right or protection of a director of the Corporation existing hereunder with respect to any act or omission occurring prior to such repeal or modification.

ARTICLE IX

Executive Committee

The Board, pursuant to the By-laws of the Corporation or by resolution passed by a majority of the then-authorized number of directors, may designate any of their number to constitute an Executive Committee, which Executive Committee, to the fullest extent permitted by law and provided for in said resolution or in the By-laws of the Corporation, shall have and may exercise all of the powers of the Board in the management of the business and affairs of the Corporation, and shall have power to authorize the seal of the Corporation to be affixed to all papers that may require it.

ARTICLE X

Indemnification

A. The Corporation shall indemnify any person who was or is a party or is threatened to be made a party to any threatened, pending or completed action, suit or proceeding whether civil, criminal, administrative or investigative (other than an action by or in the right of the Corporation) by reason of the fact that he is or was a director, officer, employee or agent of the

Corporation or is or was serving at the request of the Corporation as a director, officer, employee or agent of another corporation, partnership, joint venture or other enterprise against expenses (including attorney's fees), judgments, fines and amounts paid in settlement actually and reasonably incurred by him in connection with such action, suit or proceeding, if he acted in good faith and in a manner he reasonably believed to be in or not opposed to the best interest of the Corporation and, with respect to any criminal action or proceeding, had no reasonable cause to believe that his conduct was unlawful. The termination of any action, suit or proceeding by judgment, order, settlement, conviction or upon a plea of nolo contendere or its equivalent shall not of itself create a presumption that the person did not act in good faith and in a manner which he reasonably believed to be in or not opposed to the best interest of the Corporation and with respect to any criminal action or proceeding had reasonable cause to believe that his conduct was unlawful.

B. The Corporation shall indemnify any person who was or is a party or is threatened to be made a party to any threatened, pending or completed action or suit by or in the right of the Corporation to procure a judgment in its favor by reason of the fact that he is or was a director, officer, employee or agent of the Corporation or is or was serving at the request of the Corporation as a director, officer, employee or agent of another Corporation, partnership, joint venture, trust or other enterprise against expenses (including attorney's fees) actually and reasonably incurred by him in connection with the defense or settlement of such action or suit, if he acted in good faith and in a manner he reasonably believed to be in or not opposed to the best interest of the Corporation; except that no indemnification shall be made in respect of any claim, issue or matter as to which such person shall have been adjudged to be liable to the Corporation unless and only to the extent that the court in which such action or suit was brought shall determine, upon application, that despite the adjudication of liability, but in the view of all the circumstances of the case, such person is fairly and reasonably entitled to indemnity for such expenses which the court shall deem proper.

C. Expenses incurred in defending a civil or criminal action, suit or proceeding may be paid by the Corporation in advance of the final disposition of such action, suit or proceeding upon receipt of an undertaking by or on behalf of the director, officer, employee or agent to repay such amount if it shall ultimately be determined that he is not entitled to be indemnified by the Corporation as authorized herein.

D. The Corporation may purchase (upon resolution duly adopted by the board of directors) and maintain insurance on behalf of any person who is or was a director, officer, employee or agent of the Corporation, or is or was serving at the request of the Corporation as a director, officer, employee or agent of another corporation, partnership, joint venture, trust or other enterprise against any liability asserted against him and incurred by him in any such capacity, or arising out of his status as such, whether or not the Corporation would have the power to indemnify him against such liability.

E. To the extent that a director, officer, employee or agent of the Corporation has been successful on the merits or otherwise in defense of any action, suit, or proceeding referred to herein or in defense of any claim, issue or matter therein, he shall be indemnified against expenses (including attorneys' fees) actually and reasonably incurred by him in connection therewith.

F. Every such person shall be entitled, without demand by him upon the Corporation or any action by the Corporation, to enforce his right to such indemnity in an action at law against the Corporation. The right of indemnification and advancement of expenses hereinabove provided shall not be deemed exclusive of any rights to which any such person may now or hereafter be otherwise entitled and specifically, without limiting the generality of the foregoing, shall not be deemed exclusive of any rights pursuant to statute or otherwise, of any such person in any such action, suit or proceeding to have assessed or allowed in his favor against the Corporation or otherwise, his costs and expenses incurred therein or in connection therewith or any part thereof.

ARTICLE XI

Amendment Of Corporate Documents

A. Certificate of Incorporation

In addition to any affirmative vote required by applicable law and in addition to any vote of the holders of any series of Preferred Stock provided for or fixed pursuant to the provisions of Article IV, any alteration, amendment, repeal or rescission (a “Change”) of any provision of this Certificate of Incorporation must be approved by at least a majority of the then-authorized number of directors and by the affirmative vote of the holders of at least a majority of the combined voting power of the then-outstanding shares of Voting Stock, voting together as a single class; provided, however, that if any such Change relates to Article V, VI, VII, VIII, X or XII hereof or to this Article XI, such Change must also be approved by the affirmative vote of the holders of at least 66 2/3% of the combined voting power of the then-outstanding shares of Voting Stock, voting together as a single class. Subject to the provisions hereof, the Corporation reserves the right at any time, and from time to time, to amend, alter, repeal or rescind any provision contained in this Certificate of Incorporation in the manner now or hereafter prescribed by law, and other provisions authorized by the laws of the State of Delaware at the time in force may be added or inserted, in the manner now or hereafter prescribed by law; and all rights, preferences and privileges of whatsoever nature conferred upon stockholders, directors or any other persons whomsoever by and pursuant to this Certificate of Incorporation in its present form or as hereafter amended are granted subject to the rights reserved in this article.

B. By-Laws

In addition to any affirmative vote required by law, any Change of the By-laws of the Corporation may be adopted either (i) by the Board by the affirmative vote of at least a majority of the then-authorized number of directors or (ii) by the stockholders by the affirmative vote of the holders of at least 66 2/3% of the combined voting power of the then-outstanding shares of Voting Stock, voting together as a single class.

ARTICLE XII

Definitions

For the purposes of this Certificate of Incorporation:

A. A “person” shall mean any individual, firm, corporation, partnership, limited liability company, trust, unincorporated organization or other entity.

B. “Voting Stock” means all outstanding shares of capital stock of the Corporation that pursuant to or in accordance with this Certificate of Incorporation are entitled to vote generally in the election of directors of the Corporation, and each reference herein, where appropriate, to a percentage or portion of shares of Voting Stock shall refer to such percentage or portion of the voting power of such shares entitled to vote.

[SIGNATURE PAGE TO FOLLOW]

IN WITNESS WHEREOF, this Restated Certificate of Incorporation has been duly adopted by the Board of Directors in accordance with the provisions of Section 245 of the Delaware General Corporation Law and restates and integrates but does not further amend the provisions of the Certificate of Incorporation of the Corporation as heretofore amended or supplemented and there is no discrepancy between such provisions and the provisions of this Restated Certificate of Incorporation, which has been executed by an authorized officer of the Corporation on this 20th day of November, 2003.

Devon Energy Corporation

By: /s/ J. Larry Nichols
J. Larry Nichols
Chairman and Chief Executive Officer

[SIGNATURE PAGE OF RESTATED CERTIFICATE OF INCORPORATION]

Exhibit A

CERTIFICATE OF DESIGNATIONS
of the
6.49% CUMULATIVE PREFERRED STOCK, SERIES A
of
DEVON ENERGY CORPORATION

Pursuant to Section 151 of the
General Corporation Law of the State of Delaware

DEVON ENERGY CORPORATION, a Delaware corporation (the "Corporation"), HEREBY CERTIFIES that resolutions were duly adopted by the Board of Directors of the Corporation in accordance with Section 151(g) of the General Corporation Law of the State of Delaware pursuant to the authority conferred upon the Board of Directors of the Corporation by the provisions of the Restated Certificate of Incorporation of the Corporation as follows:

RESOLVED, that a series of the Corporation's Preferred Stock, par value $1.00 per share ("Preferred Stock"), designated as 6.49% Cumulative Preferred Stock, Series A be and hereby is created and that the designation and number of shares thereof and the powers, preferences and rights thereof are as follows:

6.49% Cumulative Preferred Stock, Series A

1. *Designation and Amount; No Fractional Shares* . There shall be a series of Preferred Stock designated as "6.49% Cumulative Preferred Stock, Series A" (the "Series A Preferred Stock") and the authorized number of shares constituting such series shall be 1,500,000. The Series A Preferred Stock is issuable in whole shares only.

2. *Dividends* . Holders of shares of Series A Preferred Stock shall be entitled to receive, when, as and if declared by the Board of Directors or a duly authorized committee thereof out of funds of the Corporation legally available for payment of dividends, cumulative cash dividends at the rate of 6.49% per annum per share on the initial liquidation preference of $100.00 per share (equivalent to $6.49 per annum per share of Series A Preferred Stock). Dividends on the Series A Preferred Stock shall be payable quarterly in arrears on March 31, June 30, September 30 and December 31 of each year, commencing September 30, 1999 (each a "Dividend Payment Date"). If any date on which dividends would otherwise be payable is a Saturday, Sunday or a day on which banking institutions in the State of New York are authorized or obligated by law or executive order to close, then the dividends otherwise payable on such date shall instead be payable on the next succeeding business day. Dividends on shares of the Series A Preferred Stock shall be fully cumulative and shall accumulate (whether or not earned or declared and whether or not the Corporation has funds legally available for the payment of dividends), on a daily basis, without interest, from the previous Dividend Payment Date, except that the first dividend shall accrue, without interest, from June 30, 1999 (being the last dividend payment date on the 6.49% Cumulative Preferred Stock, Series A (the "Converted PZE Preferred Stock"), of PennzEnergy Company, a Delaware corporation ("PennzEnergy"), to be converted into Series A Preferred Stock pursuant to the Amended and Restated Agreement and Plan of Merger dated as of May 19, 1999 among Devon Energy Corporation, an Oklahoma corporation, the Corporation, Devon Oklahoma Corporation, an Oklahoma corporation, and PennzEnergy). Accumulated and

unpaid dividends shall not bear interest. Dividends shall be payable, in arrears, to holders of record as they appear in the records of the Corporation at the close of business on the applicable record date, which shall be the 15th day of the calendar month in which the applicable Dividend Payment Date falls or such other date designated by the Board of Directors of the Corporation for the payment of dividends that is not more than 30 nor less than 10 days prior to such Dividend Payment Date. Any dividend payable on the Series A Preferred Stock for any dividend period that is shorter or longer than a full quarterly period shall be computed on the basis of a 360-day year consisting of twelve 30-day months.

If, prior to 18 months after June 2, 1998 (the date of the original issuance of the Converted PZE Preferred Stock), one or more amendments to the Internal Revenue Code of 1986, as amended (the "Code"), are enacted that change the percentage of the dividends received deduction (currently 70%) as specified in section 243(a)(1) of the Code or any successor provision (the "Dividends Received Percentage"), the amount of each dividend payable (if declared) per share of Series A Preferred Stock for dividend payments made on or after the effective date of such change in the Code will be adjusted by multiplying the amount of the dividend payable described above (before adjustment) by the factor determined by the following formula (the "DRD Formula"), and rounding the result to the nearest cent (with one-half cent rounded up):

$$\frac{1-.35(1-.70)}{1-.35(1-DRP)}$$

For the purposes of the DRD Formula, "DRP" means the Dividends Received Percentage (expressed as a decimal) applicable to the dividend in question; provided, however, that if the Dividends Received Percentage applicable to the dividend in question shall be less than 50%, then the DRP shall equal .50. No amendment to the Code, other than a change in the percentage of the dividends received deduction set forth in section 243(a)(1) of the Code or any successor provision thereto, will give rise to such an adjustment. Notwithstanding the foregoing provisions, if, with respect to any such amendment, the Corporation receives either an unqualified opinion of nationally recognized independent tax counsel selected by the Corporation or a private letter ruling or similar form of authorization from the Internal Revenue Service ("IRS") to the effect that such amendment does not apply to a dividend payable on the Series A Preferred Stock, then such amendment will not result in the adjustment provided for pursuant to the DRD Formula with respect to such dividend (including, if applicable, any adjustment that would otherwise result in the payment of Post-Declaration Date Dividends or Additional Dividends as defined below). Any such opinion shall be based upon the legislation amending or establishing the Dividends Received Percentage or upon a published pronouncement of the IRS addressing such legislation. Unless the context otherwise requires, references to dividends in this Certificate of Designations will mean dividends as adjusted by the DRD Formula. The Corporation's calculation of the dividends payable, as so adjusted and as certified accurate as to calculation and reasonable as to method by the independent certified public accountants then regularly engaged by the Corporation, shall be final and not subject to review absent manifest error.

Notwithstanding anything contained in the preceding paragraph, if any such amendment to the Code which reduces the Dividends Received Percentage is enacted after the dividend payable on a Dividend Payment Date has been declared but before such Dividend Payment Date, the amount of the dividend payable on such Dividend Payment Date will not be increased; instead, an additional dividend (a "Post-Declaration Date Dividend") equal to the excess, if any, of (x) the product of the dividend paid by the Corporation on such Dividend Payment Date and the factor determined in accordance with the DRD Formula (with the DRP used in the DRD Formula equal to the greater of the Dividend Received Percentage applicable to the dividend in question and .50) over (y) the dividend paid by the Corporation on such Dividend Payment Date, will accrue and will be payable (if declared) on the next succeeding Dividend Payment Date to holders of Series A Preferred Stock on the record date applicable to the next succeeding Dividend Payment Date or, if the Series A Preferred Stock is called for redemption prior to such record date, to holders of Series A Preferred Stock on the applicable redemption date, as the case may be, in addition to any other amounts payable on such date.

If any such amendment to the Code is enacted that reduces the Dividends Received Percentage and the reduction in the Dividends Received Percentage retroactively applies to a Dividend Payment Date as to which the Corporation previously paid dividends on the Series A Preferred Stock or to a dividend payment date as to which PennzEnergy previously paid dividends on the Converted PZE Preferred Stock (each, an "Affected Dividend Payment Date"), additional dividends (the "Additional Dividends") will accrue and will be payable (if declared) on the next succeeding Dividend Payment Date (or, if such amendment is enacted after the dividend payable on such Dividend Payment Date has been declared, on the second succeeding Dividend Payment Date following the date of enactment) to holders of record on the record date applicable to such succeeding Dividend Payment Date or, if the Series A Preferred Stock is called for redemption prior to such record date, to holders of Series A Preferred Stock on the applicable redemption date, as the case may be, in an amount equal to the sum, for all Affected Dividend Payment Dates, of the excess of (x) the product of the dividend paid by the Corporation (or PennzEnergy, as applicable) on such Affected Dividend Payment Date and the factor determined in accordance with the DRD Formula (with the DRP used in the DRD Formula equal to the greater of the Dividends Received Percentage and .50 applied to such Affected Dividend Payment Date) over (y) the dividend paid by the Corporation (or PennzEnergy, as applicable) on such Affected Dividend Payment Date. The Corporation will only make one payment of Additional Dividends for any such amendment.

Notwithstanding the foregoing, no adjustment in the dividends payable by the Corporation shall be made, and no Post-Declaration Date Dividends or Additional Dividends shall be payable by the Corporation, in respect of the enactment of any amendment to the Code 18 months or more June 2, 1998.

In the event that the amount of dividends payable per share of the Series A Preferred Stock is adjusted pursuant to the DRD Formula and/or Post-Declaration Date Dividends or Additional Dividends are to be paid, the Corporation shall give notice of each such adjustment and, if applicable, any Post-Declaration Date Dividends and Additional Dividends to the holders of Series A Preferred Stock.

No dividends may be declared or paid or set apart for payment on any stock of the Company ranking on a parity with the Series A Preferred Stock with respect to the payment of dividends unless there shall also be or have been declared and paid or set apart for payment on the Series A Preferred Stock dividends for all dividend payment periods of the Series A Preferred Stock ending on or before the dividend payment date of such parity stock, ratably in proportion to the respective amounts of dividends (x) accumulated and unpaid or payable on such parity stock, on the one hand, and (y) accumulated and unpaid through the dividend payment period or periods of the Series A Preferred Stock next preceding such dividend payment date, on the other hand.

Except as set forth in the preceding paragraph, unless full cumulative dividends on the Series A Preferred Stock have been paid through the most recently completed quarterly dividend period for the Series A Preferred Stock, no dividends (other than in Common Stock of the Corporation) may be paid or declared and set apart for payment or other distribution made upon the Common Stock or on any other stock of the Corporation ranking junior to or on a parity with the Series A Preferred Stock as to dividends, nor may any Common Stock or any other stock of the Corporation ranking junior to or on a parity with the Series A Preferred Stock as to dividends be redeemed, purchased or otherwise acquired for any consideration (or any payment be made to or available for a sinking fund for the redemption of any shares of such stock; provided, however, that any moneys theretofore deposited in any sinking fund with respect to any such stock in compliance with the provisions of such sinking fund may thereafter be applied to the purchase or redemption of such stock in accordance with the terms of such sinking fund, regardless of whether at the time of such application full cumulative dividends upon shares of the Series A Preferred Stock outstanding to the most recent Dividend Payment Date shall have been paid or declared and set apart for payment) by the Corporation; provided that any such junior or parity stock or Common Stock may be converted into or exchanged for stock of the Corporation ranking junior to the Series A Preferred Stock as to dividends.

3. *Liquidation Preference* . The shares of Series A Preferred Stock shall rank, as to rights to distributions on liquidation, dissolution or winding up of the Corporation, prior to the shares of Common Stock and any other stock of the Corporation ranking junior to the Series A Preferred Stock as to rights upon liquidation, dissolution or winding up of the Corporation, so that in the event of any liquidation, dissolution or winding up of the Corporation, whether voluntary or involuntary, the holders of the Series A Preferred Stock shall be entitled to receive out of the assets of the Corporation legally available for distribution to its stockholders, an amount equal to $100 per share, plus an amount equal to all dividends (whether or not earned or declared) accrued and accumulated and unpaid on the shares of Series A Preferred Stock to the date of payment (including any Post-Declaration Date Dividends and Additional Dividends), before any distribution of assets is made to holders of shares of Common Stock or any other class or series of stock of the Corporation that ranks junior to the Series A Preferred Stock as to rights to distributions upon liquidation, dissolution or winding up. The holders of the Series A Preferred Stock shall not be entitled to receive the preferential amounts as aforesaid until the liquidation preference of any other stock of the Corporation ranking senior to the Series A Preferred Stock as to rights to distributions upon liquidation, dissolution or winding up shall have been paid (or a sum set aside therefore sufficient to provide for payment) in full. After payment of the full amount of the preferential amounts as aforesaid, the holders of shares of Series A Preferred Stock will not be entitled to any further participation in any distribution of

assets by the Corporation. If, upon any liquidation, dissolution or winding up of the Corporation, the assets of the Corporation, or proceeds thereof, distributable among the holders of shares of Series A Preferred Stock and any stock ranking on a parity with the Series A Preferred Stock as to rights to distributions on liquidation, dissolution or winding up of the Corporation shall be insufficient to pay in full the preferential amounts to which such stock would be entitled, then such assets, or the proceeds thereof, shall be distributable among such holders ratably in accordance with the respective amounts which would be payable on such shares if all amounts payable thereon were paid in full. For the purposes hereof, neither a consolidation or merger of the Corporation with or into any other corporation, nor a merger of any one or more other corporations with or into the Corporation, nor a sale, lease, exchange or transfer of all or substantially all of the Corporation's assets shall be considered a liquidation, dissolution or winding up of the Corporation.

4. *Conversion* . The Series A Preferred Stock is not convertible into, or exchangeable for, other securities or property.

5. *Voting Rights* . The Series A Preferred Stock, except as provided herein or as otherwise from time to time required by law, shall have no voting rights. Whenever, at any time or times, the equivalent of six quarterly dividends, whether or not consecutive, on the outstanding shares of Series A Preferred Stock or on any stock ranking on a parity with the Series A Preferred Stock with respect to the payments of dividends shall be in arrears, the number of directors of the Corporation shall be increased by two (without duplication of any increase made pursuant to the terms of any other series of Preferred Stock) and the holders of the Series A Preferred Stock shall have the right, with holders of shares of any one or more other series of Preferred Stock outstanding at the time upon which like voting rights have been conferred and are exercisable ("Voting Parity Stock"), voting together as a class, to vote for the election of two directors (hereinafter the "Preferred Directors" and each a "Preferred Director") to fill such newly created directorships at a special meeting called at the request of holders of Series A Preferred Stock and/or Voting Parity Stock entitled to cast not less than 25% of the votes entitled to be cast by all such Series A Preferred Stock and Voting Parity Stock outstanding (provided that no such special meeting shall be called during the period within 60 days immediately prior to the date fixed for the next annual meeting of stockholders) or at the Corporation's next annual meeting of stockholders, and at each subsequent annual meeting of stockholders until such right shall terminate as hereinafter provided. Such voting right shall continue until all dividends accumulated on such shares of Preferred Stock on which voting rights have been conferred, including the Series A Preferred Stock, for the past dividend periods and the then current dividend period shall have been fully paid or declared and a sum sufficient for the payment thereof set aside for payment, whereupon such right shall terminate, subject to revesting in the event of each and every subsequent default of the character above mentioned. Upon any termination of the right of the holders of shares of Series A Preferred Stock and Voting Parity Stock as a class to vote for directors as provided above, the term of office of all Preferred Directors then in office shall terminate immediately and the authorized number of directors shall be reduced by the number of Preferred Directors elected pursuant hereto. Any vacancy created by the removal of any Preferred Director may be filled only by the affirmative vote of the holders of shares of Series A Preferred Stock voting separately as a class (together with the holders of shares of Voting Parity Stock). If the office of any Preferred Director becomes vacant for any reason other than removal from office, the remaining Preferred Director

may choose a successor who shall hold office for the unexpired term in respect of which such vacancy occurred. At elections for such directors, each holder of shares of Series A Preferred Stock shall be entitled to one vote for each share held (the holders of shares of any other class or series of Voting Parity Stock being entitled to such number of votes, if any, for each share of such stock held as may be granted to them).

So long as any shares of any Series A Preferred Stock remain outstanding, the Corporation shall not, without the affirmative vote of the holders of at least 66-2/3% of the shares of such Series A Preferred Stock:

(i) authorize, create or issue any capital stock of the Corporation ranking, as to dividends or upon liquidation, dissolution or winding up, prior to such Series A Preferred Stock, or reclassify any authorized capital stock of the Corporation into any such shares of such capital stock or issue any obligation or security convertible into or evidencing the right to purchase any such shares of capital stock, or

(ii) amend, alter or repeal the certificate of designations for such Series A Preferred Stock, or the Restated Certificate of Incorporation of the Corporation, whether by merger, consolidation or otherwise, so as to adversely affect the powers, preferences or special rights of such Series A Preferred Stock (provided that no such adverse effect shall be deemed to result if the Series A Preferred Stock is converted or exchanged in a merger or consolidation into preferred stock of the corporation surviving such merger or consolidation or of the corporation issuing any securities into which Common Stock is converted or exchanged in such transaction if the powers, preferences and rights of such preferred stock are not different in an adverse respect from those of the Series A Preferred Stock).

Any increase in the amount of authorized Common Stock, Preference Common Stock or Preferred Stock, or any increase or decrease in the number of shares of any series of Preference Common Stock or Preferred Stock or the authorization, creation and issuance of other classes or series of Common Stock or other stock, in each case ranking on a parity with or junior to the shares of Series A Preferred Stock with respect to the payment of dividends and distributions upon liquidation, dissolution or winding up, shall not be deemed to adversely affect such powers, preferences or special rights.

The foregoing voting provisions shall not apply if, at or prior to the time when the act with respect to which such vote would otherwise be required or upon which the holders of Series A Preferred Stock shall be entitled to vote shall be effected, all outstanding shares of Series A Preferred Stock shall have been redeemed or called for redemption and sufficient funds shall have been deposited in trust to effect such redemption.

6. *Redemption* . The shares of Series A Preferred Stock shall not be redeemable prior to June 2, 2008. On and after such date, the Corporation, at its option, may redeem shares for the Series A Preferred Stock, as a whole or in part, at any time or from time to time, at a redemption price equal to $100 per share, plus, in each case, an amount equal to all dividends (whether or

not earned or declared) accrued and accumulated and unpaid (including any Post-Declaration Date Dividends and Additional Dividends) to the date fixed for redemption, without interest.

If full cumulative dividends on the Series A Preferred Stock have not been paid or set apart for payment with respect of all prior dividend periods, the Series A Preferred Stock may not be redeemed in part and the Corporation may not purchase or acquire any shares of the Series A Preferred Stock otherwise than pursuant to a purchase or exchange offer made on the same terms to all holders of the Series A Preferred Stock. If fewer than all the outstanding shares of Series A Preferred Stock are to be redeemed, the number of shares to be redeemed shall be determined by the Board of Directors and the shares to be redeemed shall be selected by lot or pro rata or by any other means determined by the Board of Directors in its sole discretion to be equitable.

In the event the Corporation shall redeem shares of Series A Preferred Stock, written notice of such redemption shall be given by first class mail, postage prepaid, mailed not less than 30 days nor more than 60 days prior to the redemption date, to each holder of record of the shares to be redeemed at such holder's address as the same appears on the stock books of the Corporation and notice shall also be given by publication during the aforesaid period prior to the redemption date in a newspaper of general circulation in the Borough of Manhattan, the City of New York; provided, however, that no failure to give such notice nor any defect therein shall affect the validity of the proceedings for the redemption of any shares of Series A Preferred Stock to be redeemed except as to the holder to whom the Corporation has failed to mail said notice or except as to the holder whose notice was defective. Each such notice shall state: (a) the redemption date; (b) the number of shares of Series A Preferred Stock to be redeemed and, if less than all the shares held by such holder are to be redeemed from such holder, the number of shares to be redeemed from such holder; (c) the redemption price and any accumulated and unpaid dividends to the redemption date; (d) the place or places where certificates for such shares are to be surrendered for payment of the redemption price, and (e) that dividends on the shares to be redeemed will cease to accrue on such redemption date (unless the Corporation shall default in providing funds for the payment of the redemption price of the shares called for redemption at the time and place specified in such notice).

If a notice of redemption has been given pursuant to this Paragraph 6 and if, on or before the date fixed for redemption, the funds necessary for such redemption shall have been set aside by the Corporation, separate and apart from its other funds, in trust for the pro rata benefit of the holders of the shares of Series A Preferred Stock so called for redemption, then, notwithstanding that any certificates for such shares have not been surrendered for cancellation, on the redemption date dividends shall cease to accrue on the shares to be redeemed, and at the close of business on the redemption date the holders of such shares shall cease to be stockholders with respect to such shares and shall have no interest in or claims against the Corporation by virtue thereof and shall have no voting or other rights with respect to such shares, except the right to receive the moneys payable upon surrender (and endorsement, if required by the Corporation) of their certificates, and the shares evidenced thereby shall no longer be outstanding. The Corporation's obligation to provide funds for the payment of the redemption price (and any accumulated and unpaid dividends to the redemption date) of the shares called for redemption shall be deemed fulfilled if, on or before a redemption date, the Corporation shall deposit, with a bank or trust company, or an affiliate of a bank or trust company, having an office or agency in

New York City and having a capital and surplus of at least $50,000,000, such funds sufficient to pay the redemption price (and any accumulated and unpaid dividends to the redemption date) of the shares called for redemption, in trust for the account of the holders of the shares to be redeemed (and so as to be and continue to be available therefor), with irrevocable instructions and authority to such bank or trust company that such funds be delivered upon redemption of the shares of Series A Preferred Stock so called for redemption.

Subject to applicable escheat laws, any moneys so set aside by the Corporation and unclaimed at the end of two years from the redemption date shall revert to the general funds of the Corporation, after which reversion the holders of such shares so called for redemption shall look only the general funds of the Corporation for the payment of the amounts payable upon such redemption. Any interest accrued on funds so deposited shall be paid to the Corporation from time to time.

Shares of Series A Preferred Stock that have been issued and reacquired in any manner, including shares purchased or redeemed, shall (upon compliance with any applicable provisions of the laws of the State of Delaware) have the status of authorized and unissued shares of the class of Preferred Stock undesignated as to series and may be redesignated and reissued as part of any series of the preferred stock.

7. *Amendment of Resolution* . The Board reserves the right from time to time to increase or decrease the number of shares that constitute the Series A Preferred Stock (but not below the number of shares thereof then outstanding) and in other respects to amend this Certificate of Designations within the limitations provided by law, this resolution and the Restated Certificate of Incorporation.

8. *Rank* . Any stock of any class or classes or series of the Corporation shall be deemed to rank:

(a) prior to shares of the Series A Preferred Stock, either as to dividends or upon liquidation, dissolution or winding up, or both, if the holders of stock of such class or classes or series shall be entitled by the terms thereof to the receipt of dividends or of amounts distributable upon liquidation, dissolution or winding up, as the case may be, in preference or priority to the holders of shares of the Series A Preferred Stock;

(b) on a parity with shares of the Series A Preferred Stock, either as to dividends or upon liquidation, dissolution or winding up, or both, whether or not the dividend rates, dividend payment dates, or redemption or liquidation prices per share thereof are different from those of the Series A Preferred Stock, if the holders of stock of such class or classes or series shall be entitled by the terms thereof to the receipt of dividends or of amounts distributed upon liquidation, dissolution or winding up, as the case may be, in proportion to their respective dividend rates or liquidation prices, without preference or priority of one over the other as between the holders of such stock and the holders of shares of Series A Preferred Stock; and

(c) junior to shares of the Series A Preferred Stock, either as to dividends or upon liquidation, dissolution or winding up, or both, if such class or classes or series shall be Common Stock or if the holders of the Series A Preferred Stock shall be entitled to the receipt of dividends

or of amounts distributable upon liquidation, dissolution or winding up, as the case may be, in preference or priority to the holders of stock of such class or classes or series.

The Series A Preferred Stock shall rank, as to dividends and upon liquidation, dissolution or winding up, senior to the Corporation's Series A Junior Participating Preferred Stock.

Exhibit B

AMENDED AND RESTATED CERTIFICATE OF DESIGNATIONS
of
SERIES A JUNIOR PARTICIPATING PREFERRED STOCK
of
DEVON ENERGY CORPORATION

Pursuant to Section 151 of the Delaware General Corporation Law

---

DEVON ENERGY CORPORATION (the "Corporation"), a corporation organized and existing under the Delaware General Corporation Law, in accordance with the provisions of Section 103 thereof, DOES HEREBY CERTIFY:

That pursuant to the authority vested in the Corporation's board of directors in accordance with the provisions of the Restated Certificate of Incorporation of the Corporation, the Corporation's board of directors on April 24, 2003 adopted the following resolution with respect to the Corporation's Series A Junior Participating Preferred Stock, none of which have been issued:

> RESOLVED, that the Authorized Officers of the Company be, and each of them hereby is, authorized to execute an Amended and Restated Certificate of Designations with respect to the Series A Junior Participating Preferred Stock, and that the designation and number of shares thereof and the voting and other powers, preferences and relative, participating, optional and other rights of the shares of such series and the qualifications, limitations and restriction thereof are as follows:

SERIES A JUNIOR PARTICIPATING PREFERRED STOCK

1. Designation and Amount. There shall be a series of Preferred Stock that shall be designated as "Series A Junior Participating Preferred Stock," and the number of shares constituting such series shall be 2,900,000. Such number of shares may be increased or decreased by resolution of the Board of Directors; provided, however, that no decrease shall reduce the number of shares of Series A Junior Participating Preferred Stock to less than the number of shares then issued and outstanding plus the number of shares issuable upon exercise of outstanding rights, options or warrants or upon conversion of outstanding securities issued by the Corporation.

2. Dividends and Distributions.

(A) Subject to the prior and superior rights of the holders of any shares of any series of Preferred Stock ranking prior and superior to the shares of Series A Junior Participating Preferred Stock with respect to dividends, the holders of shares of Series A Junior Participating Preferred Stock, in preference to the holders of shares of any class or series of stock of the Corporation ranking junior to the Series A Junior Participating Preferred Stock, shall be entitled to receive, when, as and if declared by the Board of Directors out of funds legally available for the purpose, quarterly dividends payable in cash on the 1st day of March, June, September and

December in each year (each such date being referred to herein as a “Quarterly Dividend Payment Date”), commencing on the first Quarterly Dividend Payment Date after the first issuance of a share or fraction of a share of Series A Junior Participating Preferred Stock, in an amount per share (rounded to the nearest cent) equal to the greater of (a) $1.00 or (b) the Adjustment Number (as defined below) times the aggregate per share amount of all cash dividends, and the Adjustment Number times the aggregate per share amount (payable in kind) of all non-cash dividends or other distributions other than a dividend payable in shares of Common Stock or a subdivision of the outstanding shares of Common Stock (by reclassification or otherwise), declared on the Common Stock, par value $0.10 per share, of the Corporation (the “Common Stock”) since the immediately preceding Quarterly Dividend Payment Date, or, with respect to the first Quarterly Dividend Payment Date, since the first issuance of any share or fraction of a share of Series A Junior Participating Preferred Stock. The “Adjustment Number” shall initially be 100. In the event the Corporation shall at any time (i) declare any dividend on Common Stock payable in shares of Common Stock, (ii) subdivide the outstanding Common Stock or (iii) combine the outstanding Common Stock into a smaller number of shares, then in each such case the Adjustment Number in effect immediately prior to such event shall be adjusted by multiplying such Adjustment Number by a fraction the numerator of which is the number of shares of Common Stock outstanding immediately after such event and the denominator of which is the number of shares of Common Stock that were outstanding immediately prior to such event.

(B) The Corporation shall declare a dividend or distribution on the Series A Junior Participating Preferred Stock as provided in paragraph (A) above immediately after it declares a dividend or distribution on the Common Stock (other than a dividend payable in shares of Common Stock); provided that, in the event no dividend or distribution shall have been declared on the Common Stock during the period between any Quarterly Dividend Payment Date and the next subsequent Quarterly Dividend Payment Date, a dividend of $1.00 per share on the Series A Junior Participating Preferred Stock shall nevertheless be payable on such subsequent Quarterly Dividend Payment Date.

(C) Dividends shall begin to accrue and be cumulative on outstanding shares of Series A Junior Participating Preferred Stock from the Quarterly Dividend Payment Date next preceding the date of issue of such shares of Series A Junior Participating Preferred Stock, unless the date of issue of such shares is prior to the record date for the first Quarterly Dividend Payment Date, in which case dividends on such shares shall begin to accrue from the date of issue of such shares, or unless the date of issue is a Quarterly Dividend Payment Date or is a date after the record date for the determination of holders of shares of Series A Junior Participating Preferred Stock entitled to receive a quarterly dividend and before such Quarterly Dividend Payment Date, in either of which events such dividends shall begin to accrue and be cumulative from such Quarterly Dividend Payment Date. Accrued but unpaid dividends shall not bear interest. Dividends paid on the shares of Series A Junior Participating Preferred Stock in an amount less than the total amount of such dividends at the time accrued and payable on such shares shall be allocated pro rata on a share-by-share basis among all such shares at the time outstanding. The Board of Directors may fix a record date for the determination of holders of shares of Series A Junior Participating Preferred Stock entitled to receive payment of a dividend or distribution declared thereon, which record date shall be no more than 30 days prior to the date fixed for the payment thereof.

3. Voting Rights. The holders of shares of Series A Junior Participating Preferred Stock shall have the following voting rights:

(A) Each share of Series A Junior Participating Preferred Stock shall entitle the holder thereof to a number of votes equal to the Adjustment Number on all matters submitted to a vote of the stockholders of the Corporation.

(B) Except as otherwise provided herein, in the Restated Certificate of Incorporation or by law, the holders of shares of Series A Junior Participating Preferred Stock, the holders of shares of any other class or series entitled to vote with the Common Stock and the holders of shares of Common Stock shall vote together as one class on all matters submitted to a vote of stockholders of the Corporation.

(C) (i) If at any time dividends on any Series A Junior Participating Preferred Stock shall be in arrears in an amount equal to six quarterly dividends thereon, the occurrence of such contingency shall mark the beginning of a period (herein called a “default period”) that shall extend until such time when all accrued and unpaid dividends for all previous quarterly dividend periods and for the current quarterly dividend period on all shares of Series A Junior Participating Preferred Stock then outstanding shall have been declared and paid or set apart for payment. During each default period, (1) the number of Directors shall be increased by two, effective as of the time of election of such Directors as herein provided, and (2) the holders of Preferred Stock (including holders of the Series A Junior Participating Preferred Stock) upon which these or like voting rights have been conferred and are exercisable (the “Voting Preferred Stock”) with dividends in arrears in an amount equal to six quarterly dividends thereon, voting as a class, irrespective of series, shall have the right to elect such two Directors.

(ii) During any default period, such voting right of the holders of Series A Junior Participating Preferred Stock may be exercised initially at a special meeting called pursuant to subparagraph (iii) of this Section 3(C) or at any annual meeting of stockholders, and thereafter at annual meetings of stockholders, provided that such voting right shall not be exercised unless the holders of at least one-third in number of the shares of Voting Preferred Stock outstanding shall be present in person or by proxy. The absence of a quorum of the holders of Common Stock shall not affect the exercise by the holders of Voting Preferred Stock of such voting right.

(iii) Unless the holders of Voting Preferred Stock shall, during an existing default period, have previously exercised their right to elect Directors, the Board of Directors may order, or any stockholder or stockholders owning in the aggregate not less than ten percent of the total number of shares of Voting Preferred Stock outstanding, irrespective of series, may request, the calling of a special meeting of the holders of Voting Preferred Stock, which meeting shall thereupon be called by the Chairman of the Board, the President, a Vice President or the Secretary of the Corporation. Notice of such meeting and of any annual meeting at which holders of Voting Preferred Stock are entitled to vote pursuant to this paragraph (C)(iii) shall be given to each holder of record of Voting Preferred Stock by mailing a copy of such notice to him at his last address as the same appears on the books of the Corporation. Such meeting shall be called for a time not earlier than 20 days and not later than 60 days after such order or request or, in default of the calling of such meeting within 60 days after such order or request, such meeting may be called on similar notice by any stockholder or stockholders owning in the aggregate not less than

ten percent of the total number of shares of Voting Preferred Stock outstanding. Notwithstanding the provisions of this paragraph (C)(iii), no such special meeting shall be called during the period within 60 days immediately preceding the date fixed for the next annual meeting of the stockholders.

(iv) In any default period, after the holders of Voting Preferred Stock shall have exercised their right to elect Directors voting as a class, (x) the Directors so elected by the holders of Voting Preferred Stock shall continue in office until their successors shall have been elected by such holders or until the expiration of the default period, and (y) any vacancy in the Board of Directors may be filled by vote of a majority of the remaining Directors theretofore elected by the holders of the class or classes of stock which elected the Director whose office shall have become vacant. References in this paragraph (C) to Directors elected by the holders of a particular class or classes of stock shall include Directors elected by such Directors to fill vacancies as provided in clause (y) of the foregoing sentence.

(v) Immediately upon the expiration of a default period, (x) the right of the holders of Voting Preferred Stock as a class to elect Directors shall cease, (y) the term of any Directors elected by the holders of Voting Preferred Stock as a class shall terminate and (z) the number of Directors shall be such number as may be provided for in the Restated Certificate of Incorporation or By-Laws irrespective of any increase made pursuant to the provisions of paragraph (C) of this Section 3 (such number being subject, however, to change thereafter in any manner provided by law or in the Restated Certificate of Incorporation or By-Laws). Any vacancies in the Board of Directors effected by the provisions of clauses (y) and (z) in the preceding sentence may be filled by a majority of the remaining Directors.

(D) Except as set forth herein, holders of Series A Junior Participating Preferred Stock shall have no special voting rights and their consent shall not be required (except to the extent they are entitled to vote with holders of Common Stock as set forth herein) for taking any corporate action.

4. Certain Restrictions.

(A) Whenever quarterly dividends or other dividends or distributions payable on the Series A Junior Participating Preferred Stock as provided in Section 2 are in arrears, thereafter and until all accrued and unpaid dividends and distributions, whether or not declared, on shares of Series A Junior Participating Preferred Stock outstanding shall have been paid in full, the Corporation shall not

(i) declare or pay dividends on, make any other distributions on, or redeem or purchase or otherwise acquire for consideration any shares of stock ranking junior (either as to dividends or upon liquidation, dissolution or winding up) to the Series A Junior Participating Preferred Stock;

(ii) declare or pay dividends on or make any other distributions on any shares of stock ranking on a parity (either as to dividends or upon liquidation, dissolution or winding up) with the Series A Junior Participating Preferred Stock, except dividends paid ratably on the Series A Junior Participating Preferred Stock and all such parity stock on which dividends are payable or in arrears in proportion to the total amounts to which the holders of all such shares are then entitled; or

(iii) redeem or purchase or otherwise acquire for consideration any shares of Series A Junior Participating Preferred Stock, or any shares of stock ranking on a parity with the Series A Junior Participating Preferred Stock, except in accordance with a purchase offer made in writing or by publication (as determined by the Board of Directors) to all holders of Series A Junior Participating Preferred Stock, or to all such holders and the holders of any such shares ranking on a parity therewith, upon such terms as the Board of Directors, after consideration of the respective annual dividend rates and other relative rights and preferences of the respective series and classes, shall determine in good faith will result in fair and equitable treatment among the respective series or classes.

(B) The Corporation shall not permit any subsidiary of the Corporation to purchase or otherwise acquire for consideration any shares of stock of the Corporation unless the Corporation could, under paragraph (A) of this Section 4, purchase or otherwise acquire such shares at such time and in such manner.

5. Reacquired Shares. Any shares of Series A Junior Participating Preferred Stock purchased or otherwise acquired by the Corporation in any manner whatsoever shall be retired and canceled promptly after the acquisition thereof. All such shares shall upon their cancellation become authorized but unissued shares of Preferred Stock and may be reissued as part of a new series of Preferred Stock to be created by resolution or resolutions of the Board of Directors, subject to any conditions and restrictions on issuance set forth herein.

6. Liquidation, Dissolution or Winding Up. (A) Upon any liquidation (voluntary or otherwise), dissolution or winding up of the Corporation, no distribution shall be made to the holders of shares of stock ranking junior (either as to dividends or upon liquidation, dissolution or winding up) to the Series A Junior Participating Preferred Stock unless, prior thereto, the holders of shares of Series A Junior Participating Preferred Stock shall have received $100 per share, plus an amount equal to accrued and unpaid dividends and distributions thereon, whether or not declared, to the date of such payment (the “Series A Liquidation Preference”). Following the payment of the full amount of the Series A Liquidation Preference, no additional distributions shall be made to the holders of shares of Series A Junior Participating Preferred Stock unless, prior thereto, the holders of shares of Common Stock shall have received an amount per share (the “Common Adjustment”) equal to the quotient obtained by dividing (i) the Series A Liquidation Preference by (ii) the Adjustment Number. Following the payment of the full amount of the Series A Liquidation Preference and the Common Adjustment in respect of all outstanding shares of Series A Junior Participating Preferred Stock and Common Stock, respectively, holders of Series A Junior Participating Preferred Stock and holders of shares of Common Stock shall, subject to the prior rights of all other series of Preferred Stock, if any, ranking prior thereto, receive their ratable and proportionate share of the remaining assets to be distributed in the ratio of the Adjustment Number to 1 with respect to such Series A Junior Participating Preferred Stock and Common Stock, on a per share basis, respectively.

(B) In the event, however, that there are not sufficient assets available to permit payment in full of the Series A Liquidation Preference and the liquidation preferences of all

other series of Preferred Stock, if any, that rank on a parity with the Series A Junior Participating Preferred Stock, then such remaining assets shall be distributed ratably to the holders of such parity shares in proportion to their respective liquidation preferences. In the event, however, that there are not sufficient assets available to permit payment in full of the Common Adjustment, then such remaining assets shall be distributed ratably to the holders of Common Stock.

(C) Neither the merger or consolidation of the Corporation into or with another corporation nor the merger or consolidation of any other corporation into or with the Corporation shall be deemed to be a liquidation, dissolution or winding up of the Corporation within the meaning of this Section 6, but the sale, lease or conveyance of all or substantially all the Corporation's assets shall be deemed to be a liquidation, dissolution or winding up of the Corporation within the meaning of this Section 6.

7. Consolidation, Merger, etc. In case the Corporation shall enter into any consolidation, merger, combination or other transaction in which the shares of Common Stock are exchanged for or changed into other stock or securities, cash and/or any other property, then in any such case each share of Series A Junior Participating Preferred Stock shall at the same time be similarly exchanged or changed in an amount per share equal to the Adjustment Number times the aggregate amount of stock, securities, cash and/or any other property (payable in kind), as the case may be, into which or for which each share of Common Stock is changed or exchanged.

8. Redemption. (A) The Corporation, at its option, may redeem shares of the Series A Junior Participating Preferred Stock in whole at any time and in part from time to time, at a redemption price equal to the Adjustment Number times the current per share market price (as such term is hereinafter defined) of the Common Stock on the date of the mailing of the notice of redemption, together with unpaid accumulated dividends to the date of such redemption. The "current per share market price" on any date shall be deemed to be the average of the closing price per share of such Common Stock for the ten consecutive Trading Days (as such term is hereinafter defined) immediately prior to such date; provided, however, that in the event that the current per share market price of the Common Stock is determined during a period following the announcement of (A) a dividend or distribution on the Common Stock other than a regular quarterly cash dividend or (B) any subdivision, combination or reclassification of such Common Stock and the ex-dividend date for such dividend or distribution, or the record date for such subdivision, combination or reclassification, shall not have occurred prior to the commencement of such ten Trading Day period, then, and in each such case, the current per share market price shall be properly adjusted to take into account ex-dividend trading. The closing price for each day shall be the last sales price, regular way, or, in case no such sale takes place on such day, the average of the closing bid and asked prices, regular way, in either case as reported in the principal transaction reporting system with respect to securities listed or admitted to trading on the New York Stock Exchange, or, if the Common Stock is not listed or admitted to trading on the New York Stock Exchange, on the principal national securities exchange on which the Common Stock is listed or admitted to trading, or, if the Common Stock is not listed or admitted to trading on any national securities exchange but sales price information is reported for such security, as reported by the National Association of Securities Dealers, Inc. Automated Quotations System ("NASDAQ") or such other self-regulatory organization or registered securities information processor (as such terms are used under the Securities Exchange Act of

1934, as amended) that then reports information concerning the Common Stock, or, if sales price information is not so reported, the average of the high bid and low asked prices in the over-the-counter market on such day, as reported by NASDAQ or such other entity, or, if on any such date the Common Stock is not quoted by any such entity, the average of the closing bid and asked prices as furnished by a professional market maker making a market in the Common Stock selected by the Board of Directors of the Corporation. If on any such date no such market maker is making a market in the Common Stock, the fair value of the Common Stock on such date as determined in good faith by the Board of Directors of the Corporation shall be used. The term "Trading Day" shall mean a day on which the principal national securities exchange on which the Common Stock is listed or admitted to trading is open for the transaction of business, or, if the Common Stock is not listed or admitted to trading on any national securities exchange but is quoted by NASDAQ, a day on which NASDAQ reports trades, or, if the Common Stock is not so quoted, a Monday, Tuesday, Wednesday, Thursday or Friday on which banking institutions in the State of New York are not authorized or obligated by law or executive order to close.

(B) In the event that fewer than all the outstanding shares of the Series A Junior Participating Preferred Stock are to be redeemed, the number of shares to be redeemed shall be determined by the Board of Directors and the shares to be redeemed shall be determined by lot or pro rata as may be determined by the Board of Directors or by any other method that may be determined by the Board of Directors in its sole discretion to be equitable.

(C) Notice of any such redemption shall be given by mailing to the holders of the shares of Series A Junior Participating Preferred Stock to be redeemed a notice of such redemption, first class postage prepaid, not later than the fifteenth day and not earlier than the sixtieth day before the date fixed for redemption, at their last address as the same shall appear upon the books of the Corporation. Each such notice shall state: (i) the redemption date; (ii) the number of shares to be redeemed and, if fewer than all the shares held by such holder are to be redeemed, the number of such shares to be redeemed from such holder; (iii) the redemption price; (iv) the place or places where certificates for such shares are to be surrendered for payment of the redemption price; and (v) that dividends on the shares to be redeemed will cease to accrue on the close of business on such redemption date. Any notice that is mailed in the manner herein provided shall be conclusively presumed to have been duly given, whether or not the stockholder received such notice, and failure duly to give such notice by mail, or any defect in such notice, to any holder of Series A Junior Participating Preferred Stock shall not affect the validity of the proceedings for the redemption of any other shares of Series A Junior Participating Preferred Stock that are to be redeemed. On or after the date fixed for redemption as stated in such notice, each holder of the shares called for redemption shall surrender the certificate evidencing such shares to the Corporation at the place designated in such notice and shall thereupon be entitled to receive payment of the redemption price. If fewer than all the shares represented by any such surrendered certificate are redeemed, a new certificate shall be issued representing the unredeemed shares.

(D) The shares of Series A Junior Participating Preferred Stock shall not be subject to the operation of any purchase, retirement or sinking fund.

9. Ranking. The Series A Junior Participating Preferred Stock shall rank junior to all other series of the Corporation's Preferred Stock as to the payment of dividends and the

distribution of assets, unless the terms of any such series shall provide otherwise, and shall rank senior to the Common Stock as to such matters.

10. Amendment. At any time that any shares of Series A Junior Participating Preferred Stock are outstanding, the Restated Certificate of Incorporation of the Corporation shall not be amended in any manner which would materially alter or change the powers, preferences or special rights of the Series A Junior Participating Preferred Stock so as to affect them adversely without the affirmative vote of the holders of two-thirds or more of the outstanding shares of Series A Junior Participating Preferred Stock, voting separately as a class.

11. Fractional Shares. Series A Junior Participating Preferred Stock may be issued in fractions of a share that shall entitle the holder, in proportion to such holder's fractional shares, to exercise voting rights, receive dividends, participate in distributions and to have the benefit of all other rights of holders of Series A Junior Participating Preferred Stock.

Exhibit C

CERTIFICATE OF DESIGNATIONS
of the
SPECIAL VOTING PREFERRED STOCK
of
DEVON ENERGY CORPORATION

Pursuant to Section 151 of the
General Corporation Law of the State of Delaware

DEVON ENERGY CORPORATION, a Delaware corporation (the "Corporation"), HEREBY CERTIFIES that resolutions were duly adopted by the Board of Directors of the Corporation in accordance with Section 151(g) of the General Corporation Law of the State of Delaware pursuant to authority conferred upon the Board of Directors of the Corporation by the provisions of the Restated Certificate of Incorporation of the Corporation as follows:

RESOLVED, that a series of the Corporation's Preferred Stock, par value $1.00 per share (the "Preferred Stock"), designated as Special Voting Preferred Stock be and is hereby created and that the designation and number of shares thereof and the powers, preferences and rights thereof are as follows:

Special Voting Preferred Stock

1. *Designation and Amount* . There shall be a series of Preferred Stock designated as "Special Voting Preferred Stock" (the "Special Voting Preferred Stock") and the authorized number of shares constituting such series shall be one.

2. *Dividends* . The holder of record of the share of Special Voting Preferred Stock shall not be entitled to receive any dividends from the Corporation.

3. *Voting Rights* . The holder of record of the share of Special Voting Preferred Stock shall be entitled to vote on all matters upon which holders of Common Stock of the Corporation have the right to vote, and shall be entitled to the number of votes equal to the largest number of full shares of Common Stock of the Corporation into which the shares of outstanding Series B Convertible Preferred Stock ("Series B Preferred Stock") of Ocean Energy, Inc., a subsidiary of the Corporation existing under the laws of the State of Delaware ("Ocean"), (excluding shares which are owned by the Corporation, any of its subsidiaries or any entity directly or indirectly controlled by or under common control with the Corporation) could be converted pursuant to the terms of the Series B Preferred Stock at the record date for the determination of the stockholders entitled to vote on such matters or, if no such record date is established, the date such vote is taken. Except as otherwise required by law, the holder of record of the single share of the Special Voting Preferred Stock shall not vote as a separate class and instead shall vote together with the holders of the Common Stock of the Corporation and the

holders of other securities that vote with the holders of the Common Stock of the Corporation on all matters submitted to a vote of the holders of Common Stock of the Corporation.

4. *Liquidation* . Upon any liquidation, dissolution or winding up of the Corporation, whether voluntary or involuntary, the holders of record of the share of Special Voting Preferred Stock shall be entitled to receive cash in the amount of the par value of the share of Special Voting Preferred Stock.

5. *Other Provisions* .

(a) In connection with that certain Agreement and Plan of Merger, dated as of February 23, 2003, by and among the Corporation, Devon NewCo Corporation, a Delaware corporation, and Ocean, as amended (the "Merger Agreement"), one share of the Special Voting Preferred Stock shall be issued to a trustee (together with its successors, if any, the "Trustee") pursuant to a trust agreement entered into by and among the Corporation and the Trustee (the "Trust Agreement").

(b) The Trustee shall exercise the voting rights attached to the Special Voting Preferred Stock pursuant to and in accordance with the Trust Agreement. The voting rights attached to the Special Voting Preferred Stock shall terminate pursuant to and in accordance with the Trust Agreement.

(c) At such time as the Special Voting Preferred Stock has no votes attached to it (whether because there is no Series B Preferred Stock outstanding that are not owned by the Corporation or for any other reason), the Corporation may redeem the outstanding share of Special Voting Preferred Stock for a price equal to the par value of such share of Special Voting Preferred Stock.

(d) The Special Preferred Voting Stock is not convertible into any other class or series of the capital stock of the Corporation or into cash, property or other rights.

EXHIBIT 4.8

DEVON ENERGY CORPORATION

to

THE BANK OF NEW YORK,

as Trustee

Supplemental Indenture No. 2
Dated as of August 4, 2003

to

Indenture
Dated as of March 1, 2002

$500,000,000

2.750% Senior Notes due 2006

SUPPLEMENTAL INDENTURE NO. 2 dated as of August 4, 2003 (the "Supplemental Indenture"), between DEVON ENERGY CORPORATION, a corporation duly organized and existing under the laws of the State of Delaware (herein called the "Company"), and THE BANK OF NEW YORK, a New York banking corporation, as Trustee (herein called the "Trustee").

RECITALS OF THE COMPANY

The Company has heretofore delivered to the Trustee an Indenture dated as of March 1, 2002 (the "Senior Indenture") providing for the issuance from time to time of Debt Securities of the Company (the "Debt Securities").

Section 3.01 of the Senior Indenture provides that various matters with respect to any series of Debt Securities issued under the Senior Indenture may be established in an indenture supplemental to the Senior Indenture.

Section 12.01(f) of the Senior Indenture provides for the Company and the Trustee to enter into an indenture supplemental to the Senior Indenture to establish the form or terms of Debt Securities of any series as contemplated by Sections 2.01 and 3.01 of the Senior Indenture.

All the conditions and requirements necessary to make this Supplemental Indenture, when duly executed and delivered, a valid and legally binding agreement in accordance with its terms and for the purposes herein expressed, have been performed and fulfilled.

NOW, THEREFORE, THIS INDENTURE WITNESSETH:

For and in consideration of the premises and the purchase of the series of Debt Securities provided for herein by the Holders thereof, it is mutually covenanted and agreed, for the equal and proportionate benefit of all Holders of the series of Debt Securities provided for herein, as follows:

ARTICLE ONE

RELATION TO SENIOR INDENTURE; DEFINITIONS

SECTION 1.1. RELATION TO SENIOR INDENTURE. This Supplemental Indenture constitutes an integral part of the Senior Indenture.

SECTION 1.2. DEFINITIONS. (a) For all purposes of this Supplemental Indenture, except as otherwise expressly provided for or unless the context otherwise requires:

(1) Capitalized terms used but not defined herein shall have the respective meanings assigned to them in the Senior Indenture; and

(2) All references herein to Articles and Sections, unless otherwise specified, refer to the corresponding Articles and Sections of this Supplemental Indenture.

(b) The following definitions applicable to the series of Debt Securities provided for herein shall be in addition to those indicated in Section 1.01 of the Senior Indenture:

“Adjusted Treasury Rate” means, with respect to any Redemption Date, the yield, under the heading which represents the average for the immediately preceding week, appearing in the most recently published statistical release designated “H.15(519)” or any successor publication which is published weekly by the Board of Governors of the Federal Reserve System and which establishes yields on actively traded U.S. Treasury securities adjusted to constant maturity under the caption “Treasury Constant Maturities” for the maturity corresponding to the Optional Redemption Comparable Treasury Issue (if no maturity is within three months before or after the remaining term of the Notes, yields for the two published maturities most closely corresponding to the Optional Redemption Comparable Treasury Issue will be determined and the Adjusted Treasury Rate will be interpolated or extrapolated from such yields on a straight line basis, rounding to the nearest month); or if such release (or any successor release) is not published during the week preceding the calculation date or does not contain such yields, the rate per annum equal to the semiannual equivalent yield to maturity of the Optional Redemption Comparable Treasury Issue, calculated using a price for the Optional Redemption Comparable Treasury Issue (expressed as a percentage of its principal amount) equal to the Optional Redemption Comparable Treasury Price for such Redemption Date.

“Independent Investment Banker” means UBS Securities LLC or, if such firm is unwilling or unable to serve as such, an independent investment and banking institution of national standing appointed by the Company.

“Optional Redemption Reference Treasury Dealer” means each of up to five dealers to be selected by the Company, and their respective successors; provided that if any of the foregoing ceases to be, and has no affiliate that is, a primary U.S. governmental securities dealer (a “Primary Treasury Dealer”), the Company will substitute for it another Primary Treasury Dealer.

“Optional Redemption Comparable Treasury Issue” means the U.S. Treasury security selected by an Independent Investment Banker as having a maturity comparable to the remaining term of the Notes to be redeemed that would be utilized, at the time of selection and in accordance with customary financial practice, in pricing new issues of corporate debt securities of comparable maturity to the remaining term of the Notes or, if, in the reasonable judgment of the Independent Investment Banker, there is no such security, then the Optional Redemption Comparable Treasury Issue will mean the U.S. Treasury security or securities selected by the Independent Investment Banker as having an actual or interpolated maturity or maturities comparable to the remaining term of the Notes.

“Optional Redemption Comparable Treasury Price” means (1) the average of five Optional Redemption Reference Treasury Dealer Quotations for the applicable Redemption Date, after excluding the highest and lowest Optional Redemption Reference Treasury Dealer Quotations, or (2) if the Independent Investment Banker obtains fewer than five such Optional Redemption Reference Treasury Dealer Quotations, the average of all such quotations.

“Optional Redemption Reference Treasury Dealer Quotations” means, with respect to each Optional Redemption Reference Treasury Dealer and any Redemption Date for the Notes, the average, as determined by the Independent Investment Banker of the bid and asked prices for the Optional Redemption Comparable Treasury Issue (expressed in each case as a percentage of its principal amount) quoted in writing to the Independent Investment Banker and the Trustee at 5:00 p.m., New York City time, on the third Business Day preceding such Redemption Date.

ARTICLE TWO

THE SERIES OF NOTES

SECTION 2.1. TITLE OF THE DEBT SECURITIES. There is hereby created under the Senior Indenture a series of Debt Securities designated the “2.750% Senior Notes due 2006” (the “Notes”).

SECTION 2.2. LIMITATIONS ON AGGREGATE PRINCIPAL AMOUNT. The aggregate principal amount of the Notes shall be initially limited to $500,000,000, subject to the Company’s right to increase such limit following the original issuance of the Notes upon delivery to the Trustee of a Company Order specifying any higher limit. Except as provided in this Section, the Company shall not execute and the Trustee shall not authenticate or deliver Notes in excess of such aggregate principal amount.

Nothing contained in this Section 2.2 or elsewhere in this Supplemental Indenture, or in the Notes, is intended to or shall limit execution by the Company or authentication or delivery by the Trustee of the Notes under the circumstances contemplated in Section 3.04, 3.05, 3.06, 4.06 and 12.06 of the Senior Indenture.

SECTION 2.3. INTEREST AND INTEREST RATES; MATURITY DATE OF NOTES. The Notes will bear interest at a rate of 2.750% per annum, from August 4, 2003 or from the immediately preceding Interest Payment Date to which interest has been paid or duly provided for, payable semi-annually in arrears on February 1 and August 1 of each year, commencing February 1, 2004 (each, an "Interest Payment Date"), to the Person in whose name such Note is registered at the close of business on January 15 or July 15 (whether or not a Business Day), as the case may be, next preceding such Interest Payment Date (each, a "Regular Record Date"). Interest will be computed on the basis of a 360-day year consisting of twelve 30-day months. The interest so payable on any Note which is not punctually paid or duly provided for on any Interest Payment Date shall forthwith cease to be payable to the Person in whose name such Note is registered on the relevant Regular Record Date, and such defaulted interest shall instead be payable to the Person in whose name such Note is registered on the Special Record Date or other specified date determined in accordance with Section 3.07 of the Senior Indenture.

The Notes will mature on August 1, 2006.

SECTION 2.4. REDEMPTION.

(a) The Notes shall be redeemable before their Stated Maturity in accordance with this Section 2.4 and otherwise in accordance with the provisions of Article IV of the Senior Indenture. In the event of any conflict between this Section 2.4 (including the definitions of terms used herein) and Article IV of the Senior Indenture (including the definitions of terms used therein), this Section 2.4 shall control.

(b) The Notes may be redeemed at any time at the option of the Company as set forth in the form of Note attached as Exhibit A hereto.

SECTION 2.5. PLACES OF PAYMENT. The Places of Payment where the Notes may be presented or surrendered for payment, where the Notes may be surrendered for registration of transfer or exchange and where notices and demands to or upon the Company in respect of the Notes and the Senior Indenture may be served shall be at the Corporate Trust Office of the Trustee in the State of New York which shall initially be located at 101 Barclay Street, 21 West, New York, New York 10286.

SECTION 2.6. METHOD OF PAYMENT. Payment of the principal of, premium, if any, and interest on Notes in definitive form will be made at the office or agency of the Company maintained for that purpose in The City of New York (which shall initially be an office or agency of the Trustee), in such coin or currency of the United States as at the time of payment is legal tender for payment of public and private debts; PROVIDED, HOWEVER, that at the option of the Company, payments of interest on the Notes may be made by check mailed to the address of the Person entitled thereto as such address shall appear in the Debt Security Register.

Payment of the principal of, premium, if any, and interest on Notes represented by a Global Security shall be made in immediately available funds to the Depositary or its nominee, as the case may be, as the Holder of such Global Security.

SECTION 2.7. CURRENCY. Principal, premium, if any, and interest on the Notes shall be payable in Dollars.

SECTION 2.8. REGISTERED SECURITIES; GLOBAL FORM. The Notes shall be issuable and transferable in fully registered form, without coupons. The Notes shall each be issued in the form of one or more permanent Global Securities. The Depositary for the Notes shall be The Depository Trust Company. The Notes shall not be issuable in definitive form except as provided in Section 2.03 of the Senior Indenture.

SECTION 2.9. FORM OF NOTES. The Notes shall be substantially in the form attached as Exhibit A hereto.

SECTION 2.10. REGISTRAR AND PAYING AGENT. The Trustee shall initially serve as Debt Security Registrar and Paying Agent for the Notes.

SECTION 2.11. EVENTS OF DEFAULT. In addition to the Events of Default specified in Section 8.01 of the Senior Indenture, the following shall constitute an Event of Default with respect to the Notes:

> "default by the Company in the payment of any principal of any Funded Debt of the Company outstanding in an aggregate principal amount in excess of $50,000,000 at the final stated maturity thereof or the occurrence of any other default thereunder, the effect of which default is to cause such Funded Debt to become, or to be declared, due prior to its final stated maturity if (A) such default in payment is not cured, by payment or otherwise, within 60 days after there has been given, by registered or certified mail, to the Company by the Trustee or to the Company and the Trustee by the Holders of at least 25% in principal amount of the outstanding Notes a written notice specifying such default and requiring it to be remedied and stating that such notice is a "Notice of Default" under the Indenture (a "Notice of Default"), and the receipt by the Company of such Notice of Default or (B) the acceleration is not rescinded or annulled or the default that caused the acceleration is not cured with 60 days after the receipt by the Company of such Notice of Default."

ARTICLE THREE

MISCELLANEOUS PROVISIONS

SECTION 3.1. RATIFICATION OF SENIOR INDENTURE. Except as expressly modified or amended hereby, the Senior Indenture continues in full force and effect and is in all respects confirmed and preserved.

SECTION 3.2 GOVERNING LAW. This Supplemental Indenture and each Note shall be governed by and construed in accordance with the laws of the State of New York. This

Supplemental Indenture is subject to the provisions of the Trust Indenture Act of 1939, as amended and shall, to the extent applicable, be governed by such provisions.

SECTION 3.3. COUNTERPARTS. This Supplemental Indenture may be executed in any number of counterparts, each of which so executed shall be deemed to be an original, but all such counterparts shall together constitute but one and the same instrument.

SECTION 3.4. RECITALS. The recitals contained herein shall be taken as statements of the Company, and the Trustee assumes no responsibility for their correctness. The Trustee makes no representations as to the validity or sufficiency of this Supplemental Indenture.

[signature page follows]

IN WITNESS WHEREOF, the parties hereto have caused this Supplemental Indenture to be duly executed by their respective officers hereunto duly authorized, all as of the day and year first written above.

DEVON ENERGY CORPORATION

By: /s/ Brian J. Jennings
Name: Brian J. Jennings
Title: Senior Vice President

THE BANK OF NEW YORK,
as Trustee

By: /s/ Van K. Brown
Name: Van K. Brown
Title: Vice President

Exhibit A to
Supplement Indenture No. 2.

UNLESS THIS SECURITY IS PRESENTED BY AN AUTHORIZED REPRESENTATIVE OF THE DEPOSITORY TRUST COMPANY ("DTC"), 55 WATER STREET, NEW YORK, NEW YORK TO THE ISSUER OR ITS AGENT FOR REGISTRATION OF TRANSFER, EXCHANGE OR PAYMENT, AND SUCH SECURITY ISSUED IS REGISTERED IN THE NAME OF CEDE & CO., OR SUCH OTHER NAME AS REQUESTED BY AN AUTHORIZED REPRESENTATIVE OF DTC, ANY TRANSFER, PLEDGE OR OTHER USE HEREOF FOR VALUE OR OTHERWISE BY OR TO ANY PERSON IS WRONGFUL, SINCE THE REGISTERED OWNER HEREOF, CEDE & CO., HAS AN INTEREST HEREIN.

UNLESS AND UNTIL THIS SECURITY IS EXCHANGED IN WHOLE OR IN PART FOR SECURITIES IN CERTIFICATED FORM, THIS SECURITY MAY NOT BE TRANSFERRED EXCEPT AS A WHOLE BY DTC TO A NOMINEE THEREOF OR BY A NOMINEE THEREOF TO DTC OR ANOTHER NOMINEE OF DTC OR BY DTC OR ANY SUCH NOMINEE TO A SUCCESSOR OF DTC OR A NOMINEE OF SUCH SUCCESSOR.

DEVON ENERGY CORPORATION

2.750% Senior Note Due 2006

Registered No. _____ PRINCIPAL AMOUNT
CUSIP NO. 25179M AF 0 $ _____

DEVON ENERGY CORPORATION, a Delaware corporation (herein referred to as the "Company" which term includes any successor entity under the Indenture referred to on the reverse hereof), for value received, hereby promises to pay to _____, or registered assigns, upon presentation, the principal sum of $ _____on August 1, 2006 (the "Stated Maturity Date") and to pay interest thereon from August 4, 2003 or from the most recent Interest Payment Date to which interest has been paid or duly provided for, semi-annually in arrears on February 1 and August 1 of each year (each, an "Interest Payment Date"), commencing February 1, 2004, at the rate of 2.750% per annum, until the principal hereof is paid or duly provided for. The interest so payable, and punctually paid or duly provided for, on any Interest Payment Date will, as provided in such Indenture, be paid to the Holder in whose name this Debt Security (or one or more Predecessor Debt Securities) is registered at the close of business on the Regular Record Date for such interest, which shall be the January 15 and July 15 (whether or not a Business Day), as the case may be, next preceding such Interest Payment Date at the office or agency of the Company maintained for such purpose; PROVIDED, HOWEVER, that such interest may be paid, at the Company's option, by mailing a check to such Holder at its registered address; PROVIDED, FURTHER, that if this Debt Security is a Global Security, such interest shall be paid in immediately available funds to the Depositary or its nominee, as the case may be, as the Holder of this Debt Security. Any such interest not so punctually paid or duly provided for shall forthwith cease to be payable to the Holder on such Regular Record Date, and

may be paid to the Holder in whose name this Debt Security (or one or more Predecessor Debt Securities) is registered at the close of business on a Special Record Date for the payment of such Defaulted Interest to be fixed by the Trustee, notice whereof shall be given to Holders of Debt Securities of this series not less than 10 days prior to such Special Record Date, or may be paid at any time in any other lawful manner not inconsistent with the requirements of any securities exchange on which the Securities of this series may be listed, and upon such notice as may be required by such exchange, all as more fully provided in the Indenture. Interest will be computed on the basis of a 360-day year consisting of twelve 30-day months.

The principal of this Debt Security payable on the Stated Maturity Date or the principal of, premium, if any, and, if the Redemption Date is not an Interest Payment Date, interest on this Security payable on the Redemption Date will be paid against presentation of this Debt Security at the office or agency of the Company maintained for that purpose in New York, New York in such coin or currency of the United States of America as at the time of payment is legal tender for the payment of public and private debts.

Interest payable on this Debt Security on any Interest Payment Date and on the Stated Maturity Date or Redemption Date, as the case may be, will include interest accrued from and including the next preceding Interest Payment Date in respect of which interest has been paid or duly provided for (or from and including August 4, 2003, if no interest has been paid on this Debt Security) to but excluding such Interest Payment Date or the Stated Maturity Date or Redemption Date, as the case may be. If any Interest Payment Date or the Stated Maturity Date or Redemption Date falls on a day that is not a Business Day, principal, premium, if any, and/or interest payable with respect to such Interest Payment Date or Stated Maturity Date or Redemption Date, as the case may be, will be paid on the next succeeding Business Day with the same force and effect as if it were paid on the date such payment was due, and no interest shall accrue on the amount so payable for the period from and after such Interest Payment Date or Stated Maturity Date or Redemption Date, as the case may be.

All payments of principal, premium, if any, and interest in respect of this Debt Security will be made by the Company in immediately available funds.

Reference is hereby made to the further provisions of this Debt Security set forth on the reverse hereof, which further provisions shall for all purposes have the same effect as if set forth at this place.

Unless the Certificate of Authentication hereon has been executed by the Trustee by manual signature of one of its authorized signatories, this Debt Security shall not be entitled to any benefit under the Indenture, or be valid or obligatory for any purpose.

IN WITNESS WHEREOF, the Company has caused this instrument to be executed by one of its duly authorized officers.

Dated: _____

DEVON ENERGY CORPORATION

By: _____
Name:
Title:

TRUSTEE'S CERTIFICATE OF AUTHENTICATION:

This is one of the Debt Securities of the series designated therein referred to in the within-mentioned Indenture.

Dated: _____

THE BANK OF NEW YORK,
as Trustee

By: _____
Authorized Signatory

[Reverse of Security]

DEVON ENERGY CORPORATION

This Debt Security is one of a duly authorized issue of securities of the Company (herein called the “Debt Securities”), issued and to be issued in one or more series under an Indenture, dated as of March 1, 2002, as supplemented by Supplemental Indenture No. 2, dated as of August 4, 2003 (as so supplemented, herein called the “Indenture”) between the Company and The Bank of New York, as Trustee (herein called the “Trustee,” which term includes any successor trustee under the Indenture with respect to the series of which this Debt Security is a part), to which Indenture and all indentures supplemental thereto reference is hereby made for a statement of the respective rights, limitations of rights, duties and immunities thereunder of the Company, the Trustee and the Holders of the Debt Securities, and of the terms upon which the Debt Securities are, and are to be, authenticated and delivered. This Debt Security is one of the duly authorized series of Debt Securities designated on the face hereof, and the aggregate principal amount of the Debt Securities to be issued under such series is initially limited to $500,000,000, subject to the Company’s right to increase such limit as provided in the Indenture (except for Debt Securities authenticated and delivered upon transfer of, or in exchange for, or in lieu of other Debt Securities). All terms used in this Debt Security which are defined in the Indenture shall have the meanings assigned to them in the Indenture.

If an Event of Default, as defined in the Indenture, with respect to the Debt Securities of this series, shall occur and be continuing, the principal amount of the Debt Securities of this series and interest accrued thereon may be declared due and payable in the manner and with the effect provided in the Indenture.

This Debt Security will be redeemable, in whole or in part, at any time, at the Company’s option, at a redemption price equal to the greater of (1) 100% of the principal amount of this Debt Security then Outstanding to be redeemed, or (2) the sum of the present values of the remaining scheduled payments of principal and interest hereon (exclusive of interest accrued to the Redemption Date) from the Redemption Date to the Stated Maturity Date computed by discounting such payments to the Redemption Date on a semiannual basis (assuming a 360-day year consisting of twelve 30-day months) at a rate equal to the sum of 15 basis points plus the Adjusted Treasury Rate on the third Business Day prior to the Redemption Date, as calculated by an Independent Investment Banker, plus, in each case, accrued and unpaid interest, up to, but not including the Redemption Date.

Notice of redemption will be given by mail to Holders of Debt Securities, not less than 30 nor more than 60 days prior to the Redemption Date, all as provided in the Indenture.

This Debt Security may be redeemed in part only in multiples of $1,000 in principal amount. In the event of redemption of this Debt Security in part only, a new Debt Security or Debt Securities for the unredeemed portion hereof shall be issued in the name of the Holder hereof upon the cancellation hereof.

The Indenture permits, with certain exceptions as provided therein, the amendment thereof and the modification of the rights and obligations of the Company and the rights of the

Holders of the Debt Securities under the Indenture at any time by the Company and the Trustee with the consent of the Holders of not less than a majority of the aggregate principal amount of all Debt Securities issued under the Indenture at the time Outstanding and directly affected thereby. The Indenture also contains provisions permitting the Holders of not less than a majority of the aggregate principal amount of the Outstanding Debt Securities, on behalf of the Holders of all such securities, to waive compliance by the Company with certain provisions of the Indenture. Furthermore, provisions in the Indenture permit the Holders of not less than a majority of the aggregate principal amount, in certain instances, of the Outstanding Debt Securities of any series to waive, on behalf of all of the Holders of Debt Securities of such series, certain past defaults under the Indenture and their consequences. Any such consent or waiver by the Holder of this Debt Security shall be conclusive and binding upon such Holder and upon all future Holders of this Debt Security and other Debt Securities issued upon the registration of transfer hereof or in exchange herefor or in lieu hereof, whether or not notation of such consent or waiver is made upon this Debt Security.

No reference herein to the Indenture and no provision of this Debt Security or of the Indenture shall alter or impair the obligation of the Company, which is absolute and unconditional, to pay the principal of, premium, if any, and interest on this Debt Security at the times, places and rate, and in the coin or currency, herein prescribed.

As provided in the Indenture and subject to certain limitations therein and herein set forth, the transfer of this Debt Security is registrable in the Debt Security Register of the Company upon surrender of this Debt Security for registration of transfer at the office or agency of the Company in any place where the principal of, premium, if any, and interest on this Debt Security are payable, duly endorsed by, or accompanied by a written instrument of transfer, in form satisfactory to the Company and the Debt Security Registrar, duly executed by the Holder hereof or by his attorney duly authorized in writing, and thereupon one or more new Debt Securities, of authorized denominations and for the same aggregate principal amount, will be issued to the designated transferee or transferees.

As provided in the Indenture and subject to certain limitations therein and herein set forth, this Debt Security is exchangeable for a like aggregate principal amount of Debt Securities of different authorized denominations but otherwise having the same terms and conditions, as requested by the Holder hereof surrendering the same.

The Debt Securities of this series are issuable only in registered form without coupons in denominations of $1,000 and any integral multiple thereof.

No service charge shall be made for any such registration of transfer or exchange, but the Company may require payment of a sum sufficient to cover any tax or other governmental charge payable in connection therewith.

Prior to due presentment of this Debt Security for registration of transfer, the Company, the Trustee and any agent of the Company or the Trustee may treat the Person in whose name this Debt Security is registered as the owner hereof for all purposes, whether or not this Debt Security be overdue, and neither the Company, the Trustee nor any such agent shall be affected by notice to the contrary.

No recourse shall be had for the payment of the principal of or premium, if any, or the interest on this Debt Security, or for any claim based hereon, or otherwise in respect hereof, or based on or in respect of the Indenture or any indenture supplemental thereto, against any past, present or future stockholder, employee, officer or director, as such, of the Company or of any successor, either directly or through the Company or any successor, whether by virtue of any constitution, statute or rule of law or by the enforcement of any assessment or penalty or otherwise, all such liability being, by the acceptance hereof and as part of the consideration for the issue hereof, expressly waived and released.

The Indenture and the Debt Securities shall be governed by and construed in accordance with the laws of the State of New York applicable to agreements made and to be performed entirely in such State.

Pursuant to a recommendation promulgated by the Committee on Uniform Security Identification Procedures, the Company has caused “CUSIP” numbers to be printed on the Debt Securities of this series as a convenience to the Holders of such Debt Securities. No representation is made as to the correctness or accuracy of such CUSIP numbers as printed on the Debt Securities, and reliance may be placed only on the other identification numbers printed hereon.

ASSIGNMENT FORM

FOR VALUE RECEIVED, the undersigned hereby sells, assigns and transfers unto

_____

(Please Print or Type Name and Address Including Zip Code of Assignee)

the within Debt Security of Devon Energy Corporation and hereby does irrevocably constitute and appoint _____ Attorney to transfer said security on the books of the within-named Corporation with full power of substitution in the premises.

_____

(Please Insert Social Security or Other Identifying Number of Assignee)

Dated: _____

_____

_____

SIGNATURE OF GUARANTEE

Signatures must be guaranteed by an “eligible guarantor institution” meeting the requirements of The Bank of New York, which requirements include membership or participation in the Security Transfer Agent Medallion Program (“STAMP”) or such other “signature guarantee program” as may be determined by The Bank of New York in addition to, or in substitution for, STAMP, all in accordance with the Securities Exchange Act of 1934 as amended.

NOTICE: The signature to this assignment must correspond with the name as it appears on the first page of the within Debt Security in every particular, without alteration or enlargement of any change whatever.

Exhibit 12

RATIOS OF EARNINGS TO FIXED CHARGES AND COMBINED FIXED CHARGES AND PREFERRED STOCK DIVIDENDS
December 31, 2003

	For the Year Ended December 31,				
	2003	2002	2001	2000	1999
EARNINGS:					
Adjusted earnings (loss) from continuing operations before income taxes	$2,203	(135)	27	1,036	(264)
Add fixed charges (see below)	569	549	229	164	126
Adjusted earnings (loss)	2,772	414	256	1,200	(138)
FIXED CHARGES AND PREFERRED STOCK DIVIDENDS:					
Gross interest expense	552	537	223	158	111
Dividends on preferred stock of a subsidiary	3	—	—	—	—
Distributions on preferred securities of subsidiary trust	—	—	—	—	7
Estimated interest component of operating lease payments	14	12	6	6	8
Fixed charges	569	549	229	164	126
Preferred stock requirements, pre-tax	16	16	16	16	6
Combined fixed charges and preferred stock dividends	585	565	245	180	132
Ratio of earnings to fixed charges	4.87	N/A	1.12	7.34	N/A
Ratio of earnings to combined fixed charges and preferred stock dividends	4.74	N/A	1.05	6.70	N/A
Insufficiency of earnings to cover fixed charges and combined fixed charges	N/A	135	N/A	N/A	264
Insufficiency of earnings to cover fixed charges and combined fixed charges and preferred stock dividends	N/A	151	N/A	N/A	270

EXHIBIT 23.1

Independent Auditors' Consent

The Board of Directors
Devon Energy Corporation:

We consent to incorporation by reference in the Registration Statements (File Nos. 333-68694, 333-32214, 333-47672, 333-44702, 333-39908, 333-85553, 333-104922, 333-104933 and 333-103679) on Form S-8 and the Registration Statements (File Nos. 333-85211, 333-50036, 333-104879 and 333-100308) on Form S-3 of Devon Energy Corporation of our report dated February 4, 2004, relating to the consolidated balance sheets of Devon Energy Corporation and subsidiaries as of December 31, 2003 and 2002 and the related consolidated statements of operations, stockholders' equity and comprehensive income (loss) and cash flows for each of the years in the three year period ended December 31, 2003, which report appears in the December 31, 2003 Annual Report on Form 10-K of Devon Energy Corporation.

Our report refers to changes in the methods of accounting for derivative instruments and hedging activities, business combinations, goodwill and asset retirement obligations.

/s/ KPMG LLP

Oklahoma City, Oklahoma
March 4, 2004

Exhibit 23.2

ENGINEER'S CONSENT

We consent to incorporation by reference in the Registration Statements (File Nos. 333-68694, 333-32214, 333-47672, 333-44702, 333-39908, 333-85553, 333-104922, 333-104933 and 333-103679) on Form S-8, and the Registration Statements (File Nos. 333-85211, 333-50036, 333-104879 and 333-100308) on Form S-3 of Devon Energy Corporation of the reference to our reports for Devon Energy Corporation, which appears in the December 31, 2003 annual report on Form 10-K of Devon Energy Corporation.

LAROCHE PETROLEUM CONSULTANTS, LTD.

By: */s/ William M. Kazmann*
William M. Kazmann
Partner

March 1, 2004

Exhibit 23.3

ENGINEER'S CONSENT

We consent to incorporation by reference in the Registration Statements (File Nos. 333-68694, 333-32214, 333-47672, 333-44702, 333-39908, 333-85553, 333-104922, 333-104933 and 333-103679) on Form S-8, and the Registration Statements (File Nos. 333-85211, 333-50036, 333-104879 and 333-100308) on Form S-3 of Devon Energy Corporation of the reference to our reports for Devon Energy Corporation, which appears in the December 31, 2003 annual report on Form 10-K of Devon Energy Corporation.

Paddock Lindstrom & Associates Ltd.

/s/ D.L. Paddock

D.L. Paddock, P. Eng.
Vice-President

March 4, 2004

Exhibit 23.4

CONSENT OF RYDER SCOTT COMPANY, L.P.

We consent to incorporation by reference in the Registration Statements (File Nos. 333-68694, 333-32214, 333-47672, 333-44702, 333-39908, 333-85553, 333-104922, 333-104933 and 333-103679) on Form S-8, and the Registration Statements (File Nos. 333-85211, 333-50036, 333-104879 and 333-100308) on Form S-3 of Devon Energy Corporation of the reference to our reports for Devon Energy Corporation, which appears in the December 31, 2003 annual report on Form 10-K of Devon Energy Corporation.

/s/ RYDER SCOTT COMPANY, L.P.
RYDER SCOTT COMPANY, L.P.

Houston, Texas
March 4, 2004

Exhibit 23.5

LETTER OF CONSENT

We consent to incorporation by reference in the Registration Statements (File Nos. 333-68694, 333-32214, 333-47672, 333-44702, 333-39908, 333-85553, 333-104922, 333-104933 and 333-103679) on Form S-8, and the Registration Statements (File Nos. 333-85211, 333-50036, 333-104879 and 333-100308) on Form S-3 of Devon Energy Corporation of the reference to our reports for Devon Energy Corporation, which appears in the December 31, 2003 annual report on Form 10-K of Devon Energy Corporation.

GILBERT LAUSTSEN JUNG
ASSOCIATES LTD.

/s/ Dana B. Laustsen
Dana B. Laustsen, P. Eng.
Executive Vice-President

Calgary, Alberta
March 4, 2004

Exhibit 23.6

ENGINEER'S CONSENT

We consent to incorporation by reference in the Registration Statements (File Nos. 333-68694, 333-32214, 333-47672, 333-44702, 333-39908, 333-85553, 333-104922, 333-104933 and 333-103679) on Form S-8, and the Registration Statements (File Nos. 333-85211, 333-50036, 333-104879 and 333-100308) on Form S-3 of Devon Energy Corporation of the reference to our reports for Devon Energy Corporation, which appears in the December 31, 2003 annual report on Form 10-K of Devon Energy Corporation.

AJM PETROLEUM CONSULTANTS

/s/ Robin G. Bertram

Robin G. Bertram
Vice President, Engineering

March 4, 2004

Exhibit 31.1

CERTIFICATION

I, J. Larry Nichols, certify that:

1. I have reviewed this annual report on Form 10-K of Devon Energy Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:

a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared; and

b) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

c) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting;

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent function):

a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ *J. Larry Nichols*
J. Larry Nichols
Chief Executive Officer

Date: March 4, 2004

Exhibit 31.2

CERTIFICATION

I, William T. Vaughn, certify that:

1. I have reviewed this annual report on Form 10-K of Devon Energy Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:

a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared; and

b) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

c) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting;

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent function):

a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ *William T. Vaughn*
William T. Vaughn
Chief Financial Officer

Date: March 4, 2004

Exhibit 32.1

CERTIFICATION

In connection with the annual report of Devon Energy Corporation ("Devon") on Form 10-K for the period ended December 31, 2003 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, J. Larry Nichols, Chief Executive Officer of Devon, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Devon.

/s/ J. Larry Nichols
J. Larry Nichols
Chief Executive Officer

Date: March 4, 2004

Exhibit 32.2

CERTIFICATION

In connection with the annual report of Devon Energy Corporation ("Devon") on Form 10-K for the period ended December 31, 2003 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, William T. Vaughn, Chief Financial Officer of Devon, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Devon.

/s/ William T. Vaughn
William T. Vaughn
Chief Financial Officer

Date: March 4, 2004