DEVON ENERGY CORP /OK/

FORM 10-K405

(Annual Report (Regulation S-K, item 405))

Filed 03/06/97 for the Period Ending 12/31/96

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SIC Code	1311 - Crude Petroleum and Natural Gas
Fiscal Year	12/31

DEVON ENERGY CORP /OK/

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(Annual Report (Regulation S-K, item 405))

Filed 3/6/1997 For Period Ending 12/31/1996

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Fiscal Year	12/31

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D. C. 20549

FORM 10-K

(Mark One)

X ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 For the fiscal year ended December 31, 1996 OR TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
Commission File Number 1-10067

DEVON ENERGY CORPORATION

(Exact Name of Registrant as Specified in its Charter)

Oklahoma (State or Other Jurisdiction of Incorporation or Organization)	73-1474008 (I.R.S. Employer Identification No.)
20 North Broadway, Suite 1500 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 shares	American 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 at least the past 90 days. Yes /x/ No

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

The aggregate market value of the voting stock held by non-affiliates of the Registrant as of February 24, 1997 was $1,020,619,000. At such date 32,141,295 shares of common stock were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Proxy statement for the 1997 annual meeting of stockholders - Part III

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DEFINITIONS

As used in this document:

"Mcf" means thousand cubic feet

"MMcf" means million cubic feet "Bcf" means billion cubic feet "Bbl" means barrel "MBbls" means thousand barrels "MMBbls" means million barrels "Boe" means equivalent barrels of oil "MBoe" means thousand equivalent barrels of oil "MMBoe" means million equivalent barrels of oil "Oil" includes crude oil and condensate "NGLs" means natural gas liquids

FORWARD LOOKING STATEMENTS

This document contains "forward looking statements" as defined by the Securities Litigation Reform Act of 1995. These statements should be read in conjunction with the cautionary statements included in this document, including those found under "Item 2. Properties - Proved Reserves and Estimated Future Net Revenues" and "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations."

PART I

ITEM 1. BUSINESS

General

Devon Energy Corporation ("Devon" or the "Company") is an independent energy company engaged primarily in oil and gas exploration, development and production, and in the acquisition of producing properties. Through its predecessors, Devon began operations in 1971. In 1988 the Company's common stock began trading publicly on the American Stock Exchange under the symbol DVN. The principal and administrative offices of Devon are located at 20 North Broadway, Suite 1500, Oklahoma City, OK 73102-8260 (telephone 405/235-3611).

Devon currently owns interests in approximately 2,200 oil and gas properties concentrated in five operating areas: the Permian Basin in southeastern New Mexico and western Texas; the San Juan Basin in northwestern New Mexico; the Rocky Mountain region in Wyoming; the Mid-continent region in Oklahoma and the Texas Panhandle; and the Western Canada Sedimentary Basin in Alberta, Canada. (A detailed description of the significant properties can be found under "Item 2. Properties - Significant Properties" beginning on page 16 hereof.)

At December 31, 1996, Devon's estimated proved reserves were 179.3 MMBoe, which were balanced between oil and NGLs (45%) and natural gas (55%). The present value of pre-tax future net revenues discounted at 10% per annum assuming unescalated prices ("10% Present Value") of such reserves was $1.6 billion. Devon is one of the top 20 public independent oil and gas companies in the United States, as measured by oil and gas reserves.

Strategy

Devon's primary objectives are to build 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 from existing oil and gas properties.

During 1988, Devon expanded its capital base with its first issuance of common stock to the public. This transaction began a substantial expansion program which has continued through the subsequent nine years. Devon has used a two-pronged growth strategy of acquiring producing properties and engaging in drilling activities.

In the last five years alone, Devon has consummated six significant acquisitions and drilled 637 new wells, 614 of which were producers. These activities have resulted in reserve additions of 196.9 million Boe. Capital costs incurred to complete these activities totaled $743.2 million, for a five-year finding and development cost of $3.77 per Boe. Reserve additions and adjustments, minus production and property sales, resulted in an annual average reserve replacement factor of 435%.

Devon's objective, however, is to increase value per share, not simply to increase total assets. Reserves have grown from 3.12 Boe per fully-diluted share at year-end 1991 to 4.84 Boe per fully-diluted share at year-end 1996. During this same five- year period, net debt (long-term debt minus working capital) has remained relatively low, never exceeding $1.17 per Boe, and was zero at year-end 1996.

The oil and gas industry is characterized by volatile product prices. Devon's management believes that by (a) keeping debt levels low, (b) concentrating its properties in core areas to achieve economies of scale, (c) acquiring and developing high profit margin properties, (d) continually disposing of marginal and non-strategic properties and (e) balancing reserves between oil and gas, Devon's profitability will be maximized, even during periods of low oil and/or gas prices. In addition, Devon remains financially flexible to take advantage of opportunities for mergers, acquisitions, exploration or other growth opportunities.

Recent Developments

During 1996 Devon completed two notable transactions which had a significantly positive impact on the Company's size and financial strength. These two transactions are discussed below.

Trust Convertible Preferred Offering. On July 3, 1996, Devon Financing Trust, a Delaware business trust organized by Devon, closed a $149.5 million private placement of 6-1/2% trust convertible preferred securities (the "TCP Securities"). The net proceeds of $144.7 million were used to repay substantially all of Devon's then outstanding bank debt. This increased Devon's unused borrowing capacity, which can be used for future acquisitions and drilling projects.

The TCP Securities, which do not mature until June, 2026, are convertible at the holders' option into Devon common stock at a conversion price of $30.50 per common share. The securities are redeemable at Devon's option beginning on June 18, 1999. See note 9 to Devon's consolidated financial statements included herein for a detailed description of the TCP Securities.

Kerr-McGee Transaction. On December 31, 1996, Devon acquired the North American onshore oil and gas exploration and production properties and business of Kerr-McGee Corporation (the "KMG-NAOS Properties") in exchange for 9,954,000 shares of Devon common stock (the "Kerr-McGee Transaction"). The transaction increased Devon's year-end 1996 reserves by 62 MMBoe, or approximately 50%, and tripled the Company's net undeveloped leasehold inventory to 490,000 net acres. The KMG-NAOS Properties are concentrated in the Permian Basin, the Rocky Mountains and the Mid-Continent regions of the United States - areas in which Devon previously owned significant reserves - and in the Western Canada Sedimentary Basin of Alberta, Canada, which is a new producing province for Devon.

After consummation of the Kerr-McGee Transaction, Kerr-McGee Corporation ("Kerr-McGee") owns 31% (26% on a fully-diluted basis) of Devon's outstanding common stock. Because of Kerr- McGee's relatively large ownership position, Devon and Kerr-McGee entered into two agreements which define and limit their respective rights and obligations. In addition, Devon's board of directors amended Devon's share rights plan so that Devon's existing anti-takeover defenses will remain in force for third parties and/or certain further transactions with Kerr-McGee. Each of these arrangements are defined in the Stock Rights and Restrictions Agreement, the Registration Rights Agreement, the First Amendment to the Rights Agreement and the Second Amendment to the Rights Agreement. These documents are included as exhibits to this Form 10-K.

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. The majority of Devon's drilling operations in 1997 will be concentrated in the Permian Basin, Rocky Mountains and Gulf Coast regions of the U.S. and in the Western Canada Sedimentary Basin of Alberta, Canada.

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

Development Wells

	Gross (1)			Net (2)		
	Productive	Dry	Total	Productive	Dry	Total
1992	53	2	55	7.84	0.12	7.96
1993	92	4	96	43.39	1.40	44.79
1994	77	1	78	44.40	0.28	44.68
1995	184	3	187	143.87	0.29	144.16
1996	188	3	191	137.05	0.95	138.00
	594	13	607	376.55	3.04	379.59

Exploratory Wells

	Gross (1)			Net (2)		
	Productive	Dry	Total	Productive	Dry	Total
1992	3	1	4	1.09	0.25	1.34
1993	4	2	6	2.05	0.49	2.54
1994	2	3	5	0.52	2.37	2.89
1995	9	3	12	2.53	1.18	3.71
1996	2	1	3	1.50	0.08	1.58
	20	10	30	7.69	4.37	12.06

(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, 1996, Devon was participating in the drilling of 30 gross (14.51 net) wells which are not included in the table above. Through February 24, 1997, six gross (1.30 net) of these wells were completed as productive and the remaining wells were still in progress.

Customers

For the year ended December 31, 1996, one significant purchaser, Aquila Energy Marketing Corporation ("Aquila"), accounted for 45% of Devon's natural gas sales. For the year ended December 31, 1995, two significant purchasers, Aquila and Enron Gas Marketing, Inc. ("Enron"), accounted for 31% and 16%, respectively, of Devon's gas sales. For the year ended December 31, 1994, Aquila, Enron and Meridian Oil Trading, Inc. ("MOTI") accounted for 21%, 19% and 18%, respectively, of Devon's gas sales. Until September, 1995, MOTI was a significant purchaser of Devon's coal seam gas production at market-sensitive prices under the terms of a five-year contract entered into in May, 1990. Aquila and Enron purchase gas from numerous Devon properties, at variable and market-sensitive prices. Devon does not consider itself dependent upon any one of these purchasers, since other purchasers are willing to purchase this same gas production at competitive prices.

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

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

Oil and Natural Gas Marketing

Oil Marketing. Devon's oil production is sold under both long- and short-term agreements at prices negotiated between the parties.

Natural Gas Marketing. Virtually all of Devon's natural gas production is sold at variable, or market-sensitive prices. Though exact percentages vary daily, approximately 7% of such natural gas is sold under short-term contracts. The remaining 93% of Devon's natural gas is marketed under various long-term contracts (one year or more) which dedicate the natural gas to a purchaser for an extended period of time, but which still involve variable and market-sensitive pricing.

Under both long-term and short-term contracts, typically either the entire contract (in the case of short-term contracts) or the price provisions of the contract (in the case of long-term contracts) are renegotiated from daily intervals up to 90 day intervals. These market-sensitive sales are referred to as "spot market" sales. The spot market has become progressively more competitive in recent years. As a result, prices on the spot market have been volatile. From time to time Devon has withheld gas from the market due to low prices.

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 which substantially exceed those of Devon.

Seasonal Nature of Business

Generally, but not always, the demand for natural gas decreases during the summer months and increases during the winter months. Seasonal anomalies such as mild winters sometimes lessen this fluctuation. In addition, pipelines, utilities, local distribution companies and industrial users have begun to more effectively utilize natural gas storage facilities by purchasing some of their anticipated winter requirements during the summer.

Government Regulation

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

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 the failure to comply. Such laws and regulations have a significant impact on oil and gas drilling and production activities, increase the cost of doing business and, consequently, affect profitability. Inasmuch as new legislation affecting the oil and gas industry is commonplace and existing laws and regulations are frequently amended or reinterpreted, Devon is unable to predict the future cost or impact of complying with such laws and regulations.

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; submitting and implementing spill prevention plans; submitting notification relating to the presence, use and release of certain contaminants 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 prohibit 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 most of its leases in the San Juan Basin and many of the Company's leases in southeast New Mexico and Wyoming, are granted by the federal government and administered by various federal agencies. 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 Mineral Lands Leasing Act of 1920 places limitations on the number of acres of federal lands that may be leased by any entity or person in any one state. Additionally, the Mineral Lands Leasing Act of 1920 and related regulations also restrict a corporation from holding federal onshore oil and gas leases if stock of such corporation is owned by citizens of foreign countries which are not deemed reciprocal under such Act. Reciprocity depends, in large part, on whether the laws of the foreign jurisdiction discriminate against a United States citizen's ownership of rights to minerals in such jurisdiction. The purchase of shares in Devon by citizens of foreign countries with laws which are not deemed to be reciprocal under such Act could have an impact on Devon's ownership of federal leases.

Environmental and Occupational Regulations. Various federal, state and local laws and regulations concerning the discharge of contaminants 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 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 and accidental discharges of oil, salt water or other harmful substances. However, 100% coverage is not maintained concerning any environmental claim, and no coverage is maintained with respect to any award of punitive damages against Devon or any penalty or fine required to be paid by Devon because of its violation of any federal, state or local law. Devon's unreimbursed expenditures in 1996 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.

In 1992 Devon retained the services of an independent environmental engineering firm to provide a comprehensive evaluation of Devon's significant properties and to otherwise advise Devon concerning its compliance with various environmental laws. In 1993 Devon established its own internal Environmental Industrial Hygiene and Safety Department to perform these functions. 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 audits of Devon's compliance procedures.

No Price Controls on Liquid Hydrocarbons. There are currently no price controls on crude oil, condensate or NGLs.

Canadian Regulation

Canadian Government Regulation. The oil and gas industry 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 North American Free Trade Agreement. On January 1, 1994, the North American Free Trade Agreement ("NAFTA") among the governments of Canada, the U.S. and Mexico became effective. The NAFTA 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 U.S. or Mexico will be allowed provided that any export restrictions do not: (i) reduce the proportion of energy resource exported relative to domestic use, (ii) impose an export price higher than the domestic price, and (iii) disrupt normal channels of supply. All three countries are prohibited from imposing minimum export or import price requirements.

The NAFTA contemplates the reduction of Mexican restrictive trade practices in the energy sector and prohibits discriminatory border restrictions and export taxes. The agreement also contemplates clearer disciplines on regulators to ensure fair implementation of any regulatory changes and to minimize disruption of contractual arrangements, which is important for Canadian natural gas exports.

Royalties and Incentives. In addition to federal regulation, each producing province has legislation and regulations which govern land tenure, royalties, production rates, environmental protection and other matters. 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 mineral owner and the lessee. Crown royalties are determined by government regulation and are generally calculated as a percentage of the value of the gross production, and the rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date and the type of quality of the petroleum product produced.

From time to time the governments of Canada, Alberta and British Columbia have established incentive programs which have included royalty rate reductions, royalty holidays and tax credits for the purpose of encouraging oil and natural gas exploration or enhanced recovery projects. Regulations made pursuant to the Alberta Mines and Mineral Act provide various incentives for exploring and developing oil reserves in Alberta.

In Alberta, the royalty reserved to the Crown in respect of natural gas production, subject to various incentives, is between 15% and 30%, in the case of new gas, and between 15% and 35%, in the case of old gas, depending upon a prescribed or corporate average reference price. Gas produced from qualifying intervals in eligible gas wells spudded or deepened to a depth below 2,500 meters is subject to a royalty exemption, the amount of which depends on the depth of the well.

In Alberta, a producer of oil or natural gas is entitled to a credit against the royalties payable to the Crown by virtue of the Alberta Royalty Tax Credit ("ARTC") program. The ARTC program is based on a price sensitive formula, and the ARTC rate varies between 75%, at prices for oil below $100 per cubic meter, and 25%, at prices above $210 per cubic meter. The ARTC rate is applied to a maximum of $2,000,000 of Alberta Crown royalties payable for each producer or associated group of producers. Crown royalties on production from producing properties acquired from corporations claiming maximum entitlement to ARTC will generally not be eligible for ARTC. The rate is established quarterly based on the average "par price", as determined by the Alberta Department of Energy for the previous quarterly period.

Oil and natural gas royalty holidays and reductions for specific wells reduce the amount of Crown royalties paid by Devon to the provincial governments. The ARTC program provides a rebate on Crown royalties paid in respect of eligible producing properties. Both of these incentives increase the net income of Devon.

Producers of oil and natural gas in British Columbia are required to pay annual rental payments in respect of Crown leases and royalties and freehold production taxes in respect of oil and gas produced from Crown and freehold lands respectively. The amount payable as a royalty in respect of oil depends on the vintage of the oil (whether it was produced from a pool discovered before or after October 31, 1975), the quantity of oil produced in a month and the value of the oil. Oil produced from newly discovered pools may be exempt from the payment of a royalty for the first 36 months of production. The royalty payable on natural gas is determined by a sliding scale based on a reference price which is the greater of the amount obtained by the producer and at prescribed minimum price. Gas produced in association with oil has a minimum royalty of 8% while the royalty in respect of other gas may not be less than 15%.

Canadian Environmental Regulation. The oil and natural gas industry is currently subject to environmental regulation pursuant to 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. In Alberta, environmental compliance has been governed by the Environmental Protection and Enhancement Act (Alberta) (the "EPEA") since September 1, 1993. In addition to replacing a variety of older statutes which related to environmental matters, the EPEA also imposes certain new environmental responsibilities on oil and natural gas operators in Alberta and in certain instances also imposes greater penalties for violations. Devon is committed to meeting its responsibilities to protect the environment wherever it operates and anticipates making increased, although not material, expenditures of both a capital and expense nature as a result of the increasingly stringent laws relating to the protection of the environment.

Natural Gas Regulations. Natural gas sold within the Province of Alberta is not subject to regulation. Prices are negotiated and established based upon prevailing market conditions. Natural gas sold outside Alberta can only be removed from the province under a removal permit, issued by the Government of Alberta. The Government, through the Alberta Energy and Utilities Board ("AEUB"), will issue a removal permit only after assessing the reserves from the proposed pools supporting the application, and to a lesser extent reviewing the pricing provisions of the sales contract.

Natural gas exported to the United States is subject to approval by the National Energy Board of the Government of Canada. Exports can be approved provided that the National Energy Board is satisfied that Canadian demand will be met from current and expected supplies and the sale is of net benefit to Canada. While export prices are determined by negotiation between the buyer and seller, the National Energy Board monitors the prices.

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 that constitutes an acquisition of control of a Canadian business requiring Government of Canada approval. The Act requires notification of the establishment of new unrelated businesses in Canada by entities not controlled by Canadians, but does not require Government of Canada approval except when the new business is related to Canada's cultural heritage or national identity.

Employees

As of December 31, 1996, Devon's staff consisted of 231 full- time employees, including 19 professionals in engineering, 8 in geology, 5 in the land department, 4 in oil and gas marketing, 30 in accounting and data processing, 7 in administration and other support positions. The Company also engages independent consulting petroleum engineers, environmental professionals, geologists, geophysicists, landmen and attorneys on a fee basis. Devon expects to add between 100 and 125 full-time employees during 1997 as a result of the Kerr-McGee Transaction. (See "Management's Discussion and Analysis of Financial Condition and Results of Operations - 1997 Estimates - General and Administrative Expenses".)

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 New Mexico, Wyoming, Texas, Oklahoma and Alberta, Canada. 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 production payments, and, to a lesser extent, overriding royalty, royalty, mineral and net profits interests and other forms of direct and indirect ownership in oil and gas properties.

Proved Reserves and Estimated Future Net Revenue

"Proved Reserves" are those quantities of oil, natural gas and NGLs which geological and engineering data demonstrate with reasonable certainty to be recoverable in the future from known reservoirs under existing economic and operating conditions. Estimates of proved reserves are strictly technical judgments, and are not knowingly influenced by attitudes of conservatism or optimism. The following table sets forth Devon's estimated proved reserves, the estimated future net revenues therefrom and the 10% Present Value thereof as of December 31, 1996. Approximately 94% of Devon's domestic proved reserves were estimated by LaRoche Petroleum Consultants, Ltd., independent petroleum engineers ("LaRoche"). The remainder of such reserves were estimated by Devon's internal staff of engineers. All of the Canadian proved reserves were calculated by the independent petroleum consultants, AMH Group Ltd. ("AMH"). In preparing their estimates, LaRoche, AMH and Devon's staff used standard geological and engineering methods generally accepted by the petroleum industry and in accordance with SEC guidelines (as described in the notes below). These estimates correspond with the method used in presenting the supplemental information on oil and gas operations in note 14 to Devon's consolidated financial statements included herein, except that federal income taxes attributable to such future net revenues have been disregarded in the presentation below.

	Total Proved Reserves	Proved Developed Reserves (1)	Proved Undeveloped Reserves (2)
Oil (MBBls)	67,481	60,202	7,279
Gas (MMcf)	595,519	570,265	25,254
NGLs (MBoe)	12,579	11,212	1,367
MBoe (3)	179,313	166,457	12,856
Pre-tax Future Net Revenue ($ thousands)(4)	2,863,536	2,677,459	186,077
Pre-tax 10% Present Value ($ thousands)(4)	1,621,992	1,532,021	89,971

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

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

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

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

These amounts were calculated using prices and costs in effect as of December 31, 1996. 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 $24.52 per Bbl of oil, $3.35 per Mcf of natural gas ($3.43 per Mcf including the effect of the San Juan Basin Transaction), and $23.34 per Boe of NGLs. These prices compare to benchmark prices of $24.25 for West Texas Intermediate crude oil and $3.67 for Texas Gulf Coast spot gas.

No estimates of Devon's proved reserves have been filed with or included in reports to any federal or foreign governmental authority or agency since the beginning of the last fiscal year except (i) in filings with the SEC and (ii) in filings with the Department of Energy ("DOE"). Reserve estimates filed by Devon with the SEC correspond with the estimates of Devon reserves contained herein. Reserve estimates filed with the DOE are based upon the same underlying assumptions as the estimates of Devon's reserves included herein. However, the DOE requires reports to include the interests of all owners in wells which Devon operates and to exclude all interests in wells which 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, 1996. 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 NGL 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.

The following table presents the net quantities of Devon's oil, natural gas and NGL reserves as of the end of the years indicated. Approximately 88%, 95%, 91%, 92% and 94% of Devon's domestic reserves as of the years ended December 31, 1992, 1993, 1994, 1995 and 1996, respectively, were estimated by LaRoche. The balance of the domestic reserves were estimated by Devon's internal staff of engineers. All of the 1996 Canadian reserves were calculated by AMH.

	Total Proved Reserves			Proved Developed Reserves		
As of December 31,	Oil(MBbls)	Gas(MMcf)	NGLs(MBoe)	Oil(MBbls)	Gas(MMcf)	NGLs(MBoe)
1992	16,349	263,598	1,011	13,823	249,154	797
1993	14,897	369,254	1,854	11,548	355,536	1,751
1994	42,165	347,560	5,442	18,718	324,302	3,123
1995	44,466	363,846	9,469	28,703	311,664	6,149
1996	67,481	595,519	12,579	60,202	570,265	11,212

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 five years ended December 31, 1996, is set forth in "Item 6. Selected Financial Data."

Well Statistics

As of December 31, 1996, Devon had interests in 13,992 producing wells, of which 10,839 gross (1,311 net) were oil wells and 3,153 gross (760 net) were natural gas wells. Devon also held numerous overriding royalty interests in oil and gas wells, a portion of which are convertible to working interests after recovery of certain costs by third parties. After converting to working interests, these overriding royalty interests will be included in Devon's gross and net well count.

Undeveloped Acreage

The following table sets forth Devon's developed and undeveloped oil and gas lease and mineral acreage as of December 31, 1996.

	Developed		Undeveloped	
	Gross(1)	Net(2)	Gross(1)	Net(2)
Alabama	6,166	2,608	400	78
Arkansas	9,091	1,830	12,184	2,517
Colorado	6,588	3,065	22,368	9,568
Kansas	20,676	8,912	6,160	581
Louisiana	14,981	5,373	14,663	6,990
Mississippi	9,224	575	825	222
Montana	16,486	445	11,891	1,779
Nebraska	160	80	6,517	1,377
New Mexico	157,075	68,882	218,135	69,554
North Dakota	17,157	6,030	6,982	755
Oklahoma	294,069	88,904	190,461	38,356
South Dakota	5,771	152	322	238
Texas	839,851	227,654	600,725	176,096
Utah	5,305	864	600	600
Wyoming	253,146	103,967	160,001	106,432
Total U. S.	1,655,746	519,341	1,252,234	415,143
Canada	187,277	75,637	118,808	75,262
Grand Total	1,843,023	594,978	1,371,042	490,405

(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 operations of oil and gas properties is 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 2,006 of its 13,992 wells. As operator, Devon receives reimbursement for direct expenses incurred in the performance of its duties as well as monthly per- well producing and drilling overhead reimbursement at rates customarily charged in the area to or by unaffiliated third parties. In presenting its financial data, Devon records the monthly overhead reimbursements as a reduction of general and administrative expense, which is a common industry practice.

Significant Properties

The following table sets forth information on the most significant geographic areas in which Devon's properties are located as of December 31, 1996.

	Oil(MBbls)	Gas(MMcf)	NGLs(MBoe)	MBoe(1)	MBoe%(2)	10% Present Value(3) ($000)	Value%(4)
Permian Basin:							
West Texas and							
Southeast New Mexico							
Grayburg-Jackson Field	22,007	7,983	1,955	25,293	14.1%	$193,637	12.0%
Ozona Field	254	64,774	1,725	12,775	7.1%	102,385	6.3%
Other	24,296	80,302	3,128	40,808	22.8%	366,870	22.6%
Total	46,557	153,059	6,808	78,876	44.0%	$662,892	40.9%
Rocky Mountains:							
Colorado and Wyoming							
Worland Unit	1,966	56,138	3,797	15,119	8.4%	$133,571	8.2%
Other	8,516	49,333	460	17,198	9.6%	169,133	10.5%
Total	10,482	105,471	4,257	32,317	18.0%	$302,704	18.7%
San Juan Basin:							
Northwest New Mexico							
Northeast Blanco Unit	4	108,789	47	18,183	10.1%	$180,724(5)	11.1%
32-9 Unit	0	53,727	0	8,955	5.0%	94,384(6)	5.8%
Other	3	511	16	104	0.1%	1,235	0.1%
Total	7	163,027	63	27,242	15.2%	$276,343	17.0%
Mid-Continent:							
Oklahoma and							
Texas Panhandle	1,982	127,752	538	23,812	13.3%	$224,326	13.8%
Canada	7,530	40,858	884	15,223	8.5%	$135,389(7)	8.3%
All Other Properties	923	5,352	29	1,843	1.0%	20,338	1.3%
Grand Total	67,481	595,519	12,579	179,313	100.0%	$1,621,992	100.0%

(1) Gas reserves are converted to MBoe at the rate of six MMcf of gas per MBbl of oil, based upon the approximate relative energy content of natural gas to oil, which rate is not necessarily indicative of the relationship of gas to oil prices. The respective prices of gas and oil are affected by market and other factors in addition to relative energy content.
(2) Percentage which MBoe for the basin or region bears to total MBoe for all Proved Reserves.
(3) Determined in accordance with SEC guidelines, except that no effect is given to future income taxes.
(4) Percentage which present value for the basin or region bears to total present value for all Proved Reserves.
(5) Includes $24.4 million of additional value attributable to the San Juan Basin Transaction through the year 2002.
(6) Includes $14.3 million of additional value attributable to the San Juan Basin Transaction through the year 2002.
(7) Canadian dollars converted to U. S. dollars at the rate of $1 Canadian : $0.7297 U. S.

Permian Basin Properties. The Permian Basin is a prolific oil and gas producing province located in western Texas and southeastern New Mexico. The area encompasses approximately 66,000 square miles and contains more than 500 major oil and gas fields. Oil and gas leases within the Permian Basin are difficult to obtain as much of the most prospective acreage is "held by production" from existing wells or tied to large dedicated federal exploration units. Since 1987, Devon has made four significant acquisitions of properties in the Permian Basin. These acquisitions have enabled Devon to obtain prospective acreage in areas in which leasehold positions could not otherwise be established. This large and well-situated leasehold position continues to provide Devon with numerous exploration and development opportunities. Devon has also initiated enhanced oil recovery projects to further expand reserves.

Grayburg-Jackson Field. Devon acquired the Grayburg-Jackson Field in 1994. The property consists of approximately 8,500 acres located in the southeastern New Mexico portion of the Permian Basin. The field produces from an 800-foot thick interval of the Grayburg and San Andres Formations at depths between 3,000 and 4,000 feet. The Grayburg-Jackson Field contains approximately one- third of Devon's proved oil reserves and is Devon's largest Permian Basin property.

Production in this field was established in the 1930's, with most of the current producing wells drilled since 1970. When Devon acquired this property in 1994, drilling by previous owners had developed the property on an average spacing of over 40 acres per well. Additional oil reserves were recovered from similar properties in the immediate vicinity by infill drilling to 20- acre per well spacing and subsequent waterflooding. Based upon analogy to these properties, Devon initiated a $65 million capital development project in 1994. The project includes drilling approximately 150 infill wells, converting selected producing wells to water injection wells and optimizing the existing waterflood. Devon substantially completed the infill drilling phase of the project in July, 1996. The majority of the field should be in the initial phases of full water injection by mid-1997. Completion of the waterflood facilities over the remainder of the field will require the additional conversion of more than 90 producing wells to injection wells, construction of a second water injection plant and installation of an additional 40 miles of injection pipeline.

At year-end 1996, production averaged approximately 3,000 Boe per day. Devon anticipates that continued water injection and completion of the waterflood facilities will further improve oil and gas recoveries.

Ozona Field. The Ozona Field encompasses more than 200,000 acres in Crockett County, Texas, situated 120 miles southeast of Midland, Texas. The field produces gas from the Canyon Formation at depths of 6,000 to 9,000 feet. The field has been developed on 80-acre spacing, with portions now being infill drilled to 40- acre spacing. Through year-end 1996, Devon drilled 34 Canyon wells. Additional significant producing wells and acreage were obtained in the Kerr-McGee Transaction.

Devon has no Canyon locations currently identified for 1997 drilling. However, it is anticipated that undrilled Canyon locations will be found on the acreage acquired by Devon in 1996.

Rocky Mountain Properties. The Rocky Mountain region includes oil and gas producing basins which are grouped together because of their geographic location rather than their geological characteristics. The area generally encompasses all or portions of the states of Colorado, Montana, New Mexico, North Dakota, Utah and Wyoming. Devon's properties are primarily located in the Big Horn and Powder River Basins in Wyoming.

Worland Property. The property lies on a 25,000-acre federal unit in Big Horn and Washakie Counties, Wyoming. In December, 1995, Devon purchased a significant interest in producing and undeveloped acreage and a natural gas processing plant on this property. In early 1996, Devon increased its working interest to 98% in the developed leases through several small acquisitions. These acquisitions also increased Devon's interest in the gas processing plant to 100% and in the undeveloped oil and gas lease acreage to approximately 99%. These acquired assets, combined with the small interest Devon previously owned, had total estimated proved reserves of 15.1 MMBoe as of year-end 1996.

The Worland property is located in the Big Horn Basin, and contains three separate fields situated along a major geologic feature referred to as a draped anticline. Seven separate horizons have proven productive on the property. The Muddy Formation and the First, Second, Third and Fourth Members of the Frontier Formation produce sweet gas from sandstone reservoirs at depths ranging from 7,100 to 9,000 feet. The underlying Phosphoria Formation produces oil and sour gas from dolomite reservoirs encountered at a depth of approximately 10,000 feet. The Tensleep Formation, the deepest proven reservoir, produces oil from sandstone at a depth of approximately 10,500 feet.

Initial oil and sour gas production was established at Worland in the 1940's from the Phosphoria Formation. Sweet gas production from the overlying Frontier and Muddy reservoirs was established in the 1960's. Tensleep oil production was established in the 1970's.

Devon believes that the property contains additional exploitation opportunities for all the proven reservoirs. Consequently, a drilling program and a 3-D seismic program have been initiated to further develop the established reservoirs and to extend and define their productive limits. Devon also has begun a program to apply modern completion and stimulation techniques to selected existing wells. Additionally, Devon plans to upgrade the existing gas processing plant from 15 MMcf of gas per day to 20 MMcf per day during the first quarter of 1997.

San Juan Basin. Devon's single largest natural gas reserve position relates to its interests in two federal units in the northwest New Mexico portion of the San Juan Basin: the 33,000 acre NEBU, in Rio Arriba and San Juan Counties, and the 22,400 acre 32-9 Unit in San Juan County. The San Juan Basin, a densely drilled area covering 3,700 square miles in central and northwestern New Mexico, has historically been considered the second largest gas producing basin in the United States. Prior to 1990, the Basin's gas production primarily came from conventional sandstone formations at a depth of about 5,500 feet. However, in the early 1980's, development of the shallower Fruitland coal formation began. Coal seam gas production has increased total production so significantly that the San Juan Basin can now arguably be considered the largest gas producing basin in the U.S. Production from the coal seams constitutes almost all of Devon's reserves in these two units.

Substantially all of Devon's interests in both of these units are a part of a transaction into which the Company entered effective January 1, 1995. See " - San Juan Basin Transaction" below.

Northeast Blanco Unit. Approximately 96%, or 104.1 Bcf, of Devon's proved reserves attributable to NEBU are associated with the Fruitland coal formation. The potential for gas production from coal seams varies depending upon the thickness of the coal formation, the type of coal in place, the depth at which it is found and other factors. NEBU is located in the central part of the San Juan Basin where each of the factors is at or near its optimum. NEBU is operated by Devon. The Company initially began developing its coal seam interest during 1988, eventually drilling 102 wells - the maximum permitted under existing 320-acre spacing on NEBU's 33,000 acres.

The current reserve estimates at NEBU assume that 55% to 65% of the coal seam gas in place can be economically recovered through existing wells. In the near term, Devon is implementing a project which may increase production and recoverable reserves. This "line looping" project involves laying additional gathering lines and installing compressors to decrease operating pressure. It was begun in mid-1996 and should be substantially completed by late 1997. Initial results from the work completed in 1996 were favorable, and year-end 1996 reserve estimates were increased slightly (approximately 2.6 Bcf) to reflect this outcome. Approximately $2.3 million is expected to be spent in 1997 to continue this development project. As part of the San Juan Basin Transaction (discussed in more detail below), a third party will pay 100% of the capital necessary to enhance production from the existing NEBU wells. Devon is entitled to retain 75% of any reserves in excess of those estimated to be in place at the time of the transaction which are developed as a result of such capital expenditures. See " - San Juan Basin Transaction" below.

Over the longer term, drilling infill wells on denser spacing or utilizing enhanced recovery techniques such as injecting carbon dioxide or nitrogen into the coal formation to force additional gas to the producing well bores, may result in further NEBU reserve and production increases. Devon and other owners in the San Juan Basin have studied and experimented with these various options to determine if additional recoveries are economically feasible. Such development projects, if undertaken, would likely result in significant additional capital expenditures; however, the timing of any such projects is presently unknown. The third party in the San Juan Basin Transaction is not obligated to pay any capital or entitled to receive any reserves associated with any new or infill wells drilled at NEBU.

32-9 Unit. The 32-9 Unit is located approximately eight miles northwest of NEBU. Geologically and operationally this property is very similar to NEBU: the coal seams at the 32-9 Unit are about the same thickness as at NEBU, the type of coal and the depth at which it is found are similar and the gas content of the coal is estimated to be approximately the same. However, the 32-9 Unit is located in an area where the coal does not appear to be as permeable as it is at NEBU. The current reserve estimates assume that 20% to 30% of the coal seam gas in place can be economically recovered through the existing wells. Thus, the 32-9 Unit wells tend to produce at lower rates but should produce for a longer period of time than the NEBU wells. There is the possibility that some infill wells may be drilled to accelerate production and possibly increase reserves; however, the timing of such drilling, if it occurs, is unknown. This unit is also being evaluated for possible mechanical improvements similar to those being implemented at NEBU.

San Juan Basin Transaction. Effective January 1, 1995, Devon and an unrelated company entered into a transaction covering substantially all of Devon's San Juan Basin coal seam properties. The effect of the transaction is that the price Devon receives for its coal seam gas production will be approximately $0.55 to $0.60 per Mcf (subject to adjustment for inflation) higher than the price the Company would otherwise receive during the period from 1995 through the year 2002. For a detailed discussion of this transaction, see note 3 to Devon's consolidated financial statements included elsewhere herein.

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 production properties and before commencement of drilling operations on undeveloped properties.

ITEM 3. LEGAL PROCEEDINGS

Devon is involved in various routine legal proceedings incidental to its business. However, there are no material pending legal proceedings to which Devon is a party or of which any of its property is subject.

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

A special meeting of Devon shareholders was held on December 6, 1996. The purpose of the meeting was to consider and vote upon two issues: (a) the issuance of 9,954,000 shares of Devon common stock to Kerr-McGee in connection with the Kerr-McGee Transaction; and (b) an amendment to Devon's certificate of incorporation to increase the number of authorized shares of Devon common stock from 120 million shares to 400 million shares.

Out of a total of 22,130,896 shares of common stock outstanding and entitled to vote, 18,773,628 shares, or 85%, were represented at the meeting in person or by proxy.

Each of the proposals being voted upon was approved. The voting results were as follows:

	Proposal (a) Shares	% (1)	Proposal (b) Shares	% (1)
For	18,508,262	83.6%	17,451,728	78.9%
Against	15,538	0.1%	1,287,950	5.8%
Abstain	32,254	0.2%	33,950	0.2%
Broker Non-Vote	217,574	1.0%	--	--

(1) Percent of total shares outstanding and entitled to vote.

PART II

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

STOCKHOLDER MATTERS

Market Price

Devon's common stock has been traded on the American Stock Exchange (the "AMEX") since September 29, 1988. Prior to September 29, 1988, Devon's common stock was privately held.

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

	High	Low	Average Daily Volume
1995:			
Quarter Ended March 31, 1995	21-3/8	16-3/4	41,268
Quarter Ended June 30, 1995	23-1/4	20	41,437
Quarter Ended September 30, 1995	23-7/8	18	39,462
Quarter Ended December 31, 1995	26	21-1/2	22,333
1996:			
Quarter Ended March 31, 1996	25-3/4	19-7/8	44,846
Quarter Ended June 30, 1996	26-1/8	22	39,268
Quarter Ended September 30, 1996	27-1/2	22-3/4	73,678
Quarter Ended December 31, 1996	36-7/8	25-1/4	93,606
1997:			
Quarter Ended March 31, 1997 (through February 24, 1997)	38-7/8	31	74,876

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. Total dividends for the years ended December 31, 1994 and 1995 were $0.12 per share. Effective December 31, 1996, Devon increased its quarterly dividend payment to $0.05 per share, making the total dividends paid in 1996 equal to $0.14 per share. Devon anticipates continuing to pay regular quarterly dividends in the foreseeable future.

On February 24, 1997, there were approximately 900 Devon Common Stock shareholders of record.

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."

		Year Ended December 31, 1996	1995	1994	1993	1992
		(Thousands, Except Per Share Data)				
OPERATING RESULTS						
Oil sales	$	80,142	55,290	38,086	38,395	27,329
Gas sales		68,049	50,732	56,372	54,876	39,973
NGL sales		14,367	6,404	4,908	4,544	1,370
Other revenue		1,459	877	1,407	942	2,892
Total revenues	$	164,017	113,303	100,773	98,757	71,564

Lease operating expenses	$	31,568	27,289	24,521	26,401		18,430
Production taxes	$	10,658	6,832	6,899	6,924		4,600
Depreciation, depletion and amortization	$	43,361	38,090	34,132	28,409		19,894
General and administrative expenses	$	9,101	8,419	8,425	7,640		6,510
Interest expense	$	5,277	7,051	5,439	3,422		2,644
Distributions on preferred securities of subsidiary trust	$	4,753	--	--	--		--
<F1>							
Net earnings	$	34,801	14,502	13,745	20,486	1	14,615
Net earnings per share:							
<F1>							
Assuming no dilution	$	1.57	0.66	0.64	0.98	1	0.94
<F1>							
Assuming full dilution	$	1.52	0.66	0.64	0.98	1	0.90
Cash dividends:							
Per preferred share	$	--	--	--	--		1.46
Per common share	$	0.14	0.12	0.12	0.09		--
Weighted average common shares outstanding		22,160	22,074	21,552	20,822		13,802
<F2>							
Ratio of earnings to fixed charges 2	$	6.76	4.54	4.80	8.24		7.97

BALANCE SHEET DATA

Total assets	$	746,251	421,564	351,448	285,553	225,972
Long-term debt	$	8,000	143,000	98,000	80,000	54,450
Convertible preferred securities of subsidiary trust	$	149,500	--	--	--	--
Stockholders' equity	$	472,404	219,041	206,406	172,900	153,267

		1996	1995	1994	1993	1992
		Year Ended December 31,				
CASH FLOW DATA						
Net cash provided by operating activities	$	86,802	61,276	46,384	63,957	30,499
<F4> <F3> EBITDA 3,4		112,689	70,763	60,928	57,792	42,024
<F5> <F4> Cash margin 4,5		95,951	59,217	55,074	52,893	38,140
PRODUCTION, PRICE AND OTHER DATA						
Production:						
Oil (MBbls)		3,816	3,300	2,467	2,337	1,446
Gas (MMcf)		35,714	36,886	39,335	35,598	28,374
NGLs (MBbl)		952	600	501	411	112
<F6> MBoe 6		10,720	10,047	9,524	8,681	6,287
Average prices:						
Oil (Per Bbl)	$	21.00	16.75	15.44	16.43	18.89
Gas (Per Mcf)	$	1.91	1.38	1.43	1.54	1.41
NGLs (Per Bbl)	$	15.09	10.68	9.79	11.06	12.28
<F6> Per Boe 6	$	15.16	11.19	10.43	11.27	10.92
Costs per Boe:						
Operating costs	$	3.94	3.40	3.30	3.84	3.66
DD&A of oil and gas properties	$	3.88	3.65	3.45	3.16	3.08
General and administrative expenses	$	0.85	0.84	0.89	0.88	1.04

<F1>
1 Net earnings for 1993 include the cumulative effect of a required change in the method of accounting for income taxes in 1993 which provided earnings of $1.3 million, or $0.06 per share.

<F2>
2 For purposes of calculating the ratio of earnings to fixed charges, (i) earnings consist of earnings before income taxes and cumulative effect of accounting change, plus fixed charges; and (ii) fixed charges consist of interest expense, distributions on preferred securities of subsidiary trust, amortization of costs relating to indebtedness and the preferred securities of subsidiary trust, and one-third of rental expense estimated to be attributable to interest.

<F3>
3 Earnings before interest (including distributions on preferred securities of subsidiary trust), taxes, depreciation, depletion and amortization.

<F4>

4 EBITDA and cash margin are indicators which are commonly used in the oil and gas industry. They should be used as supplements to, and not as substitutes for, net earnings and net cash provided by operating activities determined in accordance with generally accepted accounting principles in analyzing Devon's results of operations and liquidity.

For the years ended December 31, 1996, 1995, 1994, 1993 and 1992, net cash used in investing activities were $94.8 million, $110.6 million, $73.4 million, $74.2 million and $140.6 million, respectively. For these same periods, net cash provided by financing activities were $8.5 million, $49.8 million, $15.8 million, $24.2 million and $107.9 million, respectively.

<F5>

5 "Cash margin" equals total revenues less cash expenses. Cash expenses are all expenses other than the non-cash expenses of depreciation, depletion and amortization and deferred income tax expense. Cash margin measures the net cash which is generated by a company's operations during a given period, without regard to the period such cash is actually physically received or spent by the company. This margin ignores the non-operational effect on a company's "net cash provided by operating activities", as measured by generally accepted accounting principles, from a company's activities as an operator of oil and gas wells. Such activities produce net increases or decreases in temporary cash funds held by the operator which have no effect on net earnings of the company.

<F6>

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

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 1994 through 1996. Reference is made to "Item 6. Selected Financial Data" and "Item 8. Financial Statements and Supplementary Data."

Overview

Devon concluded 1996 financially stronger and larger than at any previous time in the company s history. Over the last three years Devon's oil and gas reserves have grown 129% to 179 million barrels of oil equivalent ("MMBoe"). The company s long-term credit lines have increased 63% over the same period, to $260 million. Total assets have increased 161% to $746 million. During the same three years Devon reduced its long-term debt from $80 million to $8 million and significantly increased stockholders equity.

Devon's operating performance has also improved by most measures over the last three years. In 1996 oil and gas production was 23% over that of 1993, to 10.7 MMBoe. The 1996 production increase coupled with a 35% increase in oil, gas and NGL prices over 1993 levels, led to revenues and earnings gains. Net earnings for 1996 climbed 70% over those of 1993, to $34.8 million. Net cash provided by operating activities rose from $46.4 million in 1994 to $61.3 million in 1995 and $86.8 <F1> million in 1996. The cash margin1 (total revenues less cash expenses) during these same three years has increased from $55.1 million in 1994 to $59.2 million in 1995 and $96.0 million in 1996.

This growth in operations was driven primarily by the following events:

Devon acquired $54 million of coal seam gas properties in the San Juan Basin in June, 1993. These properties added to Devon's already significant coal seam gas properties, production and revenues in the San Juan Basin.

Devon acquired the properties of Alta Energy Corporation through a $72 million cash and common stock merger in May 1994. The oil and gas properties

<F1>
1 "Cash margin" equals Devon's total revenues less cash expenses. Cash expenses are all expenses other than the non-cash expenses of depreciation, depletion and amortization and deferred income tax expense. Cash margin is an indicator which is commonly used in the oil and gas industry. This margin measures the net cash which is generated by a company's operations during a given period, without regard to the period such cash is actually physically received or spent by the company. This margin ignores the non-operational effects on a company's activities as an operator of oil and gas wells. Such activities produce net increases or decreases in temporary cash funds held by the operator which have no effect on net earnings of the company. Cash margin should be used as a supplement to, and not as a substitute for, net earnings and net cash provided by operating activities determined in accordance with generally accepted accounting principles in analyzing Devon's results of operations and liquidity.

acquired through the merger (the "Alta Merger Properties") added substantial oil and gas reserves, production and revenues to Devon's Permian Basin position.

Devon acquired additional interests in certain of its Wyoming oil and natural gas properties and a gas processing plant (the "Worland Properties") for approximately $57 million from December, 1995 through April, 1996.

In 1995, Devon entered into a transaction covering substantially all of its San Juan Basin coal seam gas properties (the "San Juan Basin Transaction"). This transaction added approximately $10 million to Devon's annual revenues.

On December 31, 1996, Devon acquired all of Kerr- McGee Corporation's North American onshore oil and gas exploration and production business and properties (the "KMG-NAOS Properties") in exchange for 9,954,000 shares of Devon common stock. This transaction added approximately 62 million Boe to Devon's year-end 1996 proved reserves (an increase of over 50%), as well as 370,000 net undeveloped acres of leasehold.

Devon has been successful during the last three years in its drilling efforts. Devon has spent approximately $171 million to drill 476 wells, of which 462 were completed as producers.

The following actions during the last three years improved Devon s liquidity and financial resources while reducing its bank debt:

The issuance of $22 million of additional common equity capital in 1994 for the 1994 Alta Merger.

Devon's production and revenue gains have given the company a substantially larger cash flow and, thus, capital budget.

Devon's acquisition and drilling efforts during the last three years have added 126.5 MMBoe of proved reserves to its asset base. Combined with 8.6 MMBoe of upward revisions to its reserve estimates, Devon's total reserve additions of 135.1 MMBoe during the past three years were 446% of its production of 30.3 MMBoe.

In July, 1996, Devon, through a newly-formed affiliate trust, issued $149.5 million of 6.5% Trust Convertible Preferred Securities (the "TCP Securities").

Devon's oil and gas reserve additions, production gains, revenue increases and equity additions over the past three years have allowed Devon to increase its lines of credit. Since the end of 1993, Devon's long-term credit lines have increased by $100 million to a total of $260 million at year-end 1996.

The growth exhibited by Devon over the last three years extends an eight-year expansion period for the company. This period began with Devon becoming a public company in 1988. Through its acquisitions and its drilling and development efforts, Devon has significantly increased oil and gas reserves and production over this period.

While Devon has consistently increased production over this period of time, volatility in oil and gas prices has resulted in considerable variability in earnings and cash flows. Prices for oil, natural gas and NGL s are determined primarily by prevailing market conditions. Market conditions for these products have been, and will continue to be, influenced by regional and world-wide economic growth, weather and other factors that are beyond Devon's control. Devon's future earnings and cash flows will continue to be dependent on market conditions for the company s production.

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

Because Devon can only marginally influence oil and gas prices, the company's management has focused its efforts on increasing oil and gas reserves and production and on controlling expenses. Over its eight year history as a public company, Devon has been able to significantly reduce its production and operating costs per unit of production. However, over the last two years Devon's per-unit operating costs have increased somewhat. An increase in the company's oil production as a portion of its total production and an increase in secondary recovery projects have contributed to this expense increase. (Producing oil is generally more expensive than producing gas. Also, secondary recovery projects are generally more expensive than primary production.) Higher oil and gas prices in 1996 also resulted in higher production taxes, a component of production and operating expenses. Devon's future earnings and cash flows are dependent on the company's ability to continue to contain production and operating costs at levels that allow for profitable production of its oil and gas.

Results of Operations

Devon's total revenues have risen from $100.8 million in 1994 to $113.3 million in 1995 and $164.0 million in 1996. In each of these years, oil, gas and NGL sales accounted for 99% of total revenues.

Changes in oil, gas and NGL production, prices and revenues from 1994 to 1996 are shown in the table below.

	Year Ended December 31,				
	1996	1996 vs 1995	1995	1995 vs 1994	1994
Production					
Oil (MBbls)	3,816	+16%	3,300	+34%	2,467
Gas (MMcf)	35,714	-3%	36,886	-6%	39,335
NGLs (MBbls)	952	+59%	600	+20%	501
Oil, Gas and NGLs (MBoe)	10,720	+7%	10,047	+5%	9,524
Revenues					
Per Unit of Production:					
Oil (per Bbl)	$ 21.00	+25%	16.75	+8%	15.44
Gas (per Mcf)	$1.91	+38%	1.38	-3%	1.43
NGLs (per Bbl)	$ 15.09	+41%	10.68	+9%	9.79
Oil, Gas and NGLs (per Boe)	$ 15.16	+35%	11.19	+7%	10.43
Absolute:		(Thousands)			
Oil	$80,142	+45%	55,290	+45%	38,086
Gas	$68,049	+34%	50,732	-10%	56,372
NGLs	$14,367	+124%	6,404	+30%	4,908
Oil, Gas and NGLs	$162,558	+45%	112,426	+13%	99,366

Oil Revenues 1996 vs. 1995 Oil revenues increased by $24.9 million in 1996. An increase in the average price of $4.25 per barrel in 1996 added $16.2 million to revenues. Production gains of 516,000 barrels added the remaining $8.7 million of 1996's increased oil revenues.

The Grayburg-Jackson Field acquired in the 1994 Alta Merger accounted for the majority of 1996's increased production. This field produced 1,108,000 barrels in 1996, a 37% increase over the 807,000 barrels the field produced in 1995. Production from Devon's other oil properties increased 9% in 1996, from 2,493,000 barrels in 1995 to 2,708,000 barrels in 1996.

1995 vs. 1994 Oil revenues rose $17.2 million in 1995. Substantial gains in production added $12.9 million to revenues in 1995, while higher average prices added the remaining $4.3 million.

The Grayburg-Jackson Field produced 807,000 barrels in 1995, a 296% increase from the 204,000 barrels which were produced during Devon's ownership for the last seven months of 1994. Production from Devon's other oil properties increased 10% in 1995, from 2,263,000 barrels in 1994 to 2,493,000 barrels in 1995.

Gas Revenues 1996 vs. 1995 Gas revenues increased by $17.3 million in 1996. An increase in the average gas price of $0.53 per Mcf in 1996 added $18.9 million to 1996's gas revenues. This increase was partially offset by a $1.6 million reduction in gas revenues from a drop in gas production of 1.2 Bcf.

Coal seam gas production declined by 16%, from 20.8 Bcf in 1995 to 17.4 Bcf in 1996. However, the average realized coal seam gas price rose by 30% from $1.32 per Mcf in 1995 to $1.72 per Mcf in 1996. Total coal seam gas revenues were $30.1 million in 1996 compared to $27.5 million in 1995. Coal seam gas revenues include $10.3 million in 1996 and $12.8 million in 1995 attributable to the San Juan Basin Transaction.

Total conventional gas production and revenues for 1996 were 18.3 Bcf and $37.9 million, respectively, versus 16.1 Bcf and $23.2 million in 1995. Prices for conventional gas averaged $2.08 per Mcf in 1996 compared to 1995's average of $1.44. The additional interests in the Worland Properties which were acquired in December 1995 and the first half of 1996 added 2.2 Bcf to 1996's conventional production.

1995 vs. 1994 Gas revenues decreased $5.6 million, or 10%, in 1995, due to a combination of lower production and prices. Lower production accounted for $3.5 million of the revenue decrease, while lower gas prices accounted for the remaining $2.1 million.

Gas revenues in 1995 were down despite the positive effect of the 1995 San Juan Basin Transaction. Such transaction boosted 1995's gas revenues by $11.4 million, and raised the average prices for 1995 coal seam gas and total gas production by $0.61 and $0.35 per Mcf, respectively. See Note 3 to the consolidated financial statements included elsewhere in this Form 10-K for a detailed discussion of the San Juan Basin Transaction.

Coal seam gas production declined by 5%, from 22.0 Bcf in 1994 to 20.8 Bcf in 1995. This decline of 1.2 Bcf was due to the San Juan Basin Transaction which, among other things, included the sale of a small portion of Devon's coal seam gas properties.

The average realized coal seam gas price rose by 13%, from $1.17 per Mcf in 1994 to $1.32 per Mcf in 1995. The $0.61 per Mcf increase from the San Juan Basin Transaction more than offset a $0.46 per Mcf price drop at the wellhead. Total coal seam gas revenues were $27.5 million in 1995 versus $25.7 million in 1994. Coal seam gas revenues in 1995 included $14.7 million of wellhead sales and $12.8 million of revenues attributable to the San Juan Basin Transaction. The sale of the small portion of Devon's coal seam gas properties which was part of the San Juan Basin Transaction had the effect of reducing 1995's coal seam gas revenues by $1.4 million as compared to 1994's revenues. The $12.8 million of additional gas sales received pursuant to the terms of the San Juan Basin Transaction, less the $1.4 million of wellhead sales reduction as a result of the small sale, nets to the $11.4 million increase in coal seam gas sales from the San Juan Basin Transaction referred to in the second paragraph above.

Total conventional gas production and revenues for 1995 were 16.1 Bcf and $23.2 million, respectively, versus 17.4 Bcf and $30.7 million in 1994. Prices for conventional gas averaged $1.44 per Mcf in 1995 compared to 1994's average of $1.76 per Mcf.

Production for a full year from the Alta Merger Properties, as opposed to only seven months in 1994, contributed a 0.6 Bcf increase in gas production in 1995. However, this increase and others from wells drilled in 1994 and 1995 were more than offset by reduced production from other conventional gas wells. The primary contributors to the conventional production decline in 1995 were the Ozona field, miscellaneous property sales and NEBU. High pipeline pressure and down time for repairs contributed to a 0.6 Bcf reduction in Ozona production in 1995. Various marginal wells sold in 1994 and 1995 accounted for a 0.6 Bcf reduction in 1995's conventional production. Out-of-period marketing adjustments caused the reduction in 1995 conventional gas production at NEBU.

Although Devon does not have a significant interest in conventional gas production in NEBU, it had been selling more than its normal share of production. This created an "imbalance" between Devon and the wells' other owners. This imbalance was reversed in 1995 as the other owners sold more than their normal share of production. Also in 1994, Devon received nonrecurring payments for inventory gas from NEBU. In 1995, the amounts of imbalance makeup and lack of inventory sales led to a 0.5 Bcf reduction in conventional NEBU production compared to 1994.

NGL Revenues 1996 vs. 1995 NGL revenues increased by $8.0 million in 1996. An increase in average prices of $4.41 per barrel added $4.2 million to the 1996 revenues. The remaining $3.8 million of increased revenues was attributable to increased production of 352,000 barrels in 1996.

The additional interests acquired in the Worland Properties in December 1995 and the first half of 1996 accounted for 214,000 barrels of the increased production in 1996. The Worland Properties produced 226,000 barrels in 1996 compared to 12,000 barrels in 1995. Additional drilling in the Sand Dunes area of the Permian Basin increased production from 69,000 barrels in 1995 to 95,000 barrels in 1996.

1995 vs. 1994 NGL revenues increased by $1.5 million in 1995. Higher production contributed $1.0 million of the increase, while the remaining $0.5 of increased revenues was attributable to higher average prices in 1995.

The Alta Merger Properties accounted for 52,000 barrels of the increased production. Such properties produced 84,000 barrels in 1995, compared to 32,000 barrels during the seven months Devon owned the properties in 1994. Additional drilling in the Sand Dunes area increased production from 39,000 barrels in 1994 to 69,000 barrels in 1995.

Expenses The details of the changes in pre-tax expenses between 1994 and 1996 are shown in the table below.

	Year Ended December 31,				
	1996	1996 vs 1995	1995	1995 vs 1994	1994
	(Absolute Amounts in Thousands)				
Absolute:					
Production and operating expenses:					
Lease operating expenses	$ 31,568	+16%	27,289	+11%	24,521
Production taxes	10,658	+56%	6,832	-1%	6,899
Depreciation, depletion and amortization attributable to:					
Oil and gas production	41,538	+13%	36,640	+11%	32,861
Non-oil and gas properties	1,823	+26%	1,450	+14%	1,271
General and administrative expenses	9,101	+8%	8,419	-	8,425
Interest expense	5,277	-25%	7,051	+30%	5,439
Distributions on preferred securities of subsidiary trust	4,753	N/A	-	-	-
Total	$ 104,718	+19%	87,681	+10%	79,416
<F1>					
Per Boe Produced(1):					
Production and operating expenses:					
Lease operating expenses	$2.95	+8%	2.72	+6%	2.57
Production taxes	0.99	+46%	0.68	-7%	0.73
Depreciation, depletion and amortization attributable to:					
Oil and gas production	3.88	+6%	3.65	+6%	3.45
Non-oil and gas properties	0.17	+21%	0.14	+8%	0.13
General and administrative expenses	0.85	+1%	0.84	-6%	0.89
Interest expense	0.49	-30%	0.70	+23%	0.57
Distributions on preferred securities of subsidiary trust	0.44	N/A	-	-	-
Total	$9.77	+12%	8.73	+5%	8.34

<F1>
(1) Though per Boe general and administrative expenses, interest expense, non-oil and gas property depreciation and distributions on preferred securities of subsidiary trust may be helpful for profitability trend analysis, these expenses are not directly attributable to production volumes. Rather they are an artifact of corporate structure, capitalization and financing, and non-oil and gas property fixed assets, respectively.

Production and Operating Expenses The details of the changes in production and operating expenses between 1994 and 1996 are shown in the table below.

	Year Ended December 31,				
	1996	1996 vs 1995	1995	1995 vs 1994	1994
	(Absolute Amounts in Thousands)				
Absolute:					
Recurring lease operating expenses	$ 28,270	+19%	23,842	+10%	21,583
Well workover expenses	3,298	-4%	3,447	+17%	2,938
Production taxes	10,658	+56%	6,832	-1%	6,899
Total production and operating expenses	$ 42,226	+24%	34,121	+9%	31,420
Per Boe:					
Recurring lease operating expenses	$ 2.64	+11%	2.37	+4%	2.27
Well workover expenses	0.31	-11%	0.35	+17%	0.30
Production taxes	0.99	+46%	0.68	-7%	0.73
Total production and operating expenses	$ 3.94	+16%	3.40	+3%	3.30

1996 vs. 1995 Recurring lease operating expenses increased by $4.4 million, or 19%, in 1996. Approximately $2.7 million of the increase was related to the additional interests acquired in the Worland Properties in December 1995 and the first half of 1996. Recurring lease operating expenses for the Worland Properties increased from $0.1 million in 1995 to $2.8 million in 1996 after Devon increased its ownership in such properties. The Alta Merger Properties' recurring lease operating expenses increased from $3.5 million in 1995 to $4.6 million in 1996. This increase was predominantly due to the higher number of producing wells in the Grayburg-Jackson Field in 1996 compared to 1995.

Recurring expenses per Boe were up by $0.27, or 11%, in 1996 compared to 1995. This increase was primarily caused by the reduction in the coal seam gas properties' share of total production. The recurring operating costs per Boe for these coal seam gas properties are extremely low ($0.32 per Boe in 1996 and $0.24 per Boe in 1995). However, as production from these properties declined and production from Devon's other properties increased in 1996, the coal seam gas properties' percentage of overall production dropped from 35% in 1995 to 27% in 1996. The result is that more of Devon's production in 1996 was attributable to its conventional oil and gas properties, which have a higher recurring operating cost per Boe than the low-cost coal seam gas properties. The recurring costs per Boe on Devon's conventional properties were $3.50 per Boe in 1996 and 1995. However, since these properties represented a larger percentage of Devon's total production in 1996 compared to 1995, the result was a $0.27 per Boe increase in the overall rate.

Production taxes are collected by most taxing authorities on a fixed percentage of revenue basis. Therefore, as Devon's revenues have increased, so have production taxes. Production taxes increased 56% from $6.8 million in 1995 to $10.7 million in 1996. This increase was due almost exclusively to higher oil, gas and NGL revenues. Excluding revenues generated from the San Juan Basin Transaction which are not subject to production taxes, 1996 oil, gas and NGL revenues increased 53% compared to 1995.

Production taxes per Boe increased by $0.31 per Boe, or 46% in 1996. This was primarily caused by the increase in the average price per Boe received in 1996. Excluding the effect on average prices from the San Juan Basin Transaction, Devon's total revenues per Boe increased by 43% from $9.92 per Boe in 1995 to $14.21 per Boe in 1996.

1995 vs. 1994 Recurring lease operating expenses increased by $2.2 million, or 10%, in 1995. Approximately $1.6 million of the increase was related to the Alta Merger Properties. Costs for these properties increased from $1.9 million in 1994 (for the last seven months of the year during which they were owned by Devon) to $3.5 million in 1995. However, on a cost per unit of production basis, the Alta Merger Properties' recurring lease operating expenses dropped from $4.96 per Boe in 1994 to $3.16 per Boe in 1995. These per unit costs compare to the averages for Devon's other properties of $2.15 per Boe in 1994 and $2.28 per Boe in 1995.

Depreciation, Depletion and Amortization Devon's largest non-cash expense is depreciation, depletion and amortization ("DD&A"). DD&A of oil and gas properties is calculated as the percentage of total proved reserve volumes produced during the year, multiplied by the net capitalized investment in those reserves including estimated future development costs (the "depletable base"). Generally, if reserve volumes are revised up or down, then the DD&A rate per unit of production will change inversely. However, if capitalized costs change, 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.

1996 vs. 1995 Oil and gas property related DD&A increased by $4.9 million, or 13%, in 1996. Approximately $2.5 million of this increase was caused by a 7% increase in total oil, gas and NGL production in 1996. The remaining $2.4 million increase was caused by a 6% increase in the DD&A rate from $3.65 per Boe in 1995 to $3.88 per Boe in 1996.

1995 vs. 1994 Oil and gas property related DD&A increased by $3.8 million, or 11%, in 1995. Approximately $2.0 million of this increase was caused by an increase in the DD&A rate from $3.45 per Boe in 1994 to $3.65 per Boe in 1995. The increased DD&A rate was primarily caused by the inclusion of the Alta Merger Properties for a full year in 1995, compared to only seven months in 1994. The remaining $1.8 million of the increase in oil and gas property related DD&A was caused by the increase in total production in 1995.

General and Administrative Expenses ("G&A") 1996 vs. 1995 G&A increased by $0.7 million, or 8%, in 1996. Employee salaries and related benefits were $1.1 million higher in 1996. Legal expenses and abandoned acquisition expenses were each $0.2 million higher in 1996. These increases were partially offset by a $0.1 million reduction in franchise tax expense due to Devon's 1995 change of incorporation from Delaware to Oklahoma. Also, Devon saw a $0.7 million increase in G&A reimbursements received from other joint interest owners in Devon-operated properties.

1995 vs. 1994 G&A was constant between 1995 and 1994. Employee salaries and related overhead burdens increased by $0.3 million, legal fees increased by $0.3 million and abandoned acquisition costs rose by $0.1 million. These increases were offset by a $0.6 million increase in G&A reimbursements received from joint interest owners in Devon- operated properties and a $0.1 million reduction in franchise taxes. Approximately $0.2 million of the increase in G&A reimbursements related to a change in the method used to calculate the reimbursements on certain properties, and such change was retroactive to the prior two years. The reduction in franchise taxes resulted from Devon's reincorporation from Delaware to Oklahoma in June 1995.

Interest Expense 1996 vs. 1995 Interest expense decreased by $1.8 million, or 25%, in 1996. Approximately $1.5 million of the lower interest expense was due to a lower average debt balance in 1996. The average debt balance dropped from $97.1 million in 1995 to $77.0 million in 1996. This decrease in average debt outstanding was primarily the result of the issuance of the TCP Securities in July 1996.

The remaining $0.3 million of interest expense reduction in 1996 resulted from lower interest rates. The interest rates on the debt outstanding during 1996 averaged 6.3%, compared to 1995's rate of 6.5%. The overall interest rate (including the effect of the interest rate swap discussed below, various fees paid to the banks and the amortization of certain loan costs) averaged 6.9% in 1996 and 7.3% in 1995.

Devon entered into an interest rate swap agreement in the second quarter of 1995, and terminated the agreement on July 1, 1996 for a gain of $0.8 million. This gain will be recognized ratably in Devon's operating results as a reduction to interest expense during the period from July 1, 1996 to June 16, 1998 (the original expiration date of the swap agreement). Approximately $0.2 million of the gain was included in the last half of 1996 as a reduction to interest expense. During the time when the agreement was still in effect, it resulted in $0.1 million of reduced interest expense in the year 1995, and had no effect on interest expense for the first six months of 1996.

1995 vs. 1994 Interest expense increased by $1.6 million, or 30%, in 1995. This increase was due almost exclusively to higher rates in 1995, which accounted for $1.3 million of the increased interest expense. The interest rate on the debt outstanding during 1995 was 6.5%, compared to 1994's rate of 5.2%. The overall interest rate averaged 7.3% in 1995, compared to the 1994 overall rate of 5.9%.

The remaining $0.3 million of interest expense increase in 1995 was caused by a higher average balance outstanding. The average debt balance during 1995 was $97.1 million, compared to 1994's average balance of $92.5 million.

Distributions on Preferred Securities of Subsidiary Trust 1996 vs. 1995 As mentioned in the above discussion of interest expense, and as discussed in Note 9 to the consolidated financial statements included elsewhere herein, Devon, through its newly-formed affiliate Devon Financing Trust, completed the issuance of $149.5 million of 6.5% TCP Securities in a private placement in July 1996. The distributions accrue at the rate of 1.625% per quarter. The 1996 distributions of $4.8 million represented slightly less than two quarters' distributions due to the issuance date occurring in July.

Income Taxes 1996 vs. 1995 Devon's effective financial tax rate in 1996 was 41%, compared to 1995's rate of 43%. Both rates were above the statutory federal tax rate of 35% due to state income taxes, and certain tax aspects of the San Juan Basin Transaction and the 1994 Alta Merger.

1995 vs 1994 Devon's effective financial tax rate in 1995 was 43%, compared to 1994's rate of 36%. State income taxes and certain tax aspects of the San Juan Basin Transaction were the primary factors which increased Devon's financial tax rate in 1995. The San Juan Basin Transaction also had a significant effect on the portion of income taxes which are current versus deferred.

Capital Expenditures, Capital Resources and Liquidity

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

Capital Expenditures Approximately $98.9 million of cash was spent in 1996 for capital expenditures, of which $85.0 million was related to the acquisition, drilling or development of oil and gas properties. Most of the drilling and development efforts in 1996 centered in the Permian Basin, which included 176 of the 194 oil and gas wells which Devon drilled during 1996. Most of Devon's 1996 non-oil and gas property related capital expenditures involved the $12.5 million purchase of the office building in which its Oklahoma City offices are located. This purchase was closed on December 31, 1996.

Other Cash Uses A $0.03 per common share dividend was paid in each quarter since Devon paid its initial common stock dividend in the second quarter of 1993 through the third quarter of 1996. In the fourth quarter of 1996, the quarterly dividend rate was increased to $0.05 per share.

Capital Resources and Liquidity Net cash provided by operating activities ("operating cash flow") was the primary source of capital and short-term liquidity in 1996. Operating cash flow in 1996 totaled $86.2 million, a 41% increase compared to the $61.3 million of operating cash flow generated in 1995.

In addition to operating cash flow, Devon's credit lines have been an important source of capital and liquidity. At year-end 1996, long-term credit lines totaled $260 million, of which $252 million was available for future use. At the end of 1996, in connection with the KMG-NAOS acquisition, Devon also established a demand revolving credit line for its new Canadian operations. This credit line totals $12.5 million Canadian dollars, all of which was available at year-end. (See Note 7 to the consolidated financial statements included elsewhere in this report for a detailed discussion of the credit lines.) The use of the proceeds from the TCP Securities offering in July 1996 to retire long-term debt increased the amount of Devon's credit lines available for future borrowings.

Devon's San Juan Basin coal seam gas production is subject to uncertainties regarding additional royalties and taxes. If such uncertainties are resolved in 1997, the resolutions are likely to require the use of operating cash flow, but Devon does not expect such amount to be material to its overall liquidity, capital resources or net earnings. For a complete discussion of these matters, see Note 12 to the consolidated financial statements contained elsewhere in this report.

1997 Estimates

The forward-looking statements provided in this discussion are based on management's examination of historical operating trends, the December 31, 1996 reserve reports of LaRoche and AMH, data in Devon's files and other data available from third parties. Devon cautions that its future oil, gas and NGL production, revenues and expenses are subject to all of the risks and uncertainties normally incident to the exploration for and development and production of oil and gas. These risks include, but are not limited to, environmental risks, drilling risks, regulatory changes, the uncertainty inherent in estimating future oil and gas production or reserves, and other risks as outlined below. The scope of Devon s operations increased significantly with the KMG-NAOS transaction. This increases the margin of error inherent in estimating Devon s 1997 production volumes, prices and expenses. Also, the financial results for Devon's new Canadian operations, obtained in the KMG-NAOS transaction, are subject to currency exchange rate risks.

Assumptions and Risks for 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 world-wide economic growth, weather and other substantially variable factors. These factors are beyond Devon s control and are difficult to predict. Over 90% of Devon s revenues are attributable to sales of these three commodities. Consequently, the company s financial results and resources are highly influenced by this price volatility.

Estimates for Devon s future production of oil, natural gas and NGLs are based on the assumption that market demand and prices for oil and gas will continue at levels that allow for profitable production of these products. Although Devon's management believes these assumptions to be reasonable, there can be no assurance of such stability.

Certain of Devon s individual oil and gas properties are sufficiently significant as to have a material impact on the company s overall financial results. With respect to oil production, these properties include the West Red Lake Field and the Grayburg-Jackson Unit, both in southeast New Mexico. The company s interest in NEBU and the 32-9 Unit can have a substantive effect on overall gas production.

The production, transportation 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 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 for 1997 will be substantially similar to those of 1996, unless otherwise noted. Given the general limitations expressed herein, Devon's forward-looking statements for 1997 are set forth below.

Oil Production and Relative Prices Devon expects its oil production in 1997 to total between 5.9 million barrels and 6.9 million barrels. Devon expects its net oil prices will average from between $0.05 below to $0.20 above West Texas Intermediate posted prices in 1997.

Gas Production and Relative Prices Devon expects its total gas production in 1997 will be between 64.0 Bcf and 75.0 Bcf. It is expected that coal seam gas production will be
16.5 Bcf to 19.5 Bcf. Canadian production in 1997 is estimated to be between 7.0 Bcf and 8.0 Bcf. Devon expects production from the remainder of its gas properties to total between 40.5 Bcf and 47.5 Bcf.

Devon expects its 1997 coal seam average price will be between $0.25 and $0.55 less than Texas Gulf Coast spot averages. This includes an expected $0.55 per Mcf from the San Juan Basin Transaction. Devon's Canadian gas production is expected to average from between $0.85 to $1.20 less than Texas Gulf Coast spot prices. (These Canadian differentials are expressed in U.S. dollars, using the year-end 1996 exchange rate of $0.73 U.S. dollar to $1.00 Canadian dollar.) Devon's remaining gas production is expected to average $0.05 to $0.25 less than Texas Gulf Coast spot prices during 1997.

NGL Production Devon expects its production of NGLs in 1997 to total between 1.1 million barrels and 1.3 million barrels.

Production and Operating Expenses Devon's production and operating expenses vary in response to several factors. Among the most significant of these factors are additions or deletions to the company's property base, changes in production taxes, general changes in the prices of services and materials that are used in the operation of the company's properties and the amount of repair and workover activity required on the company's properties.

The addition of the KMG-NAOS Properties is expected to be the largest contributor to an increase in recurring lease operating expenses in 1997. The additional revenues contributed by these properties should also cause production taxes to rise. In addition, well workover expenses are anticipated to increase in 1997.

Oil, gas and NGL prices will have a direct effect on production taxes to be incurred in 1997. Future prices could also have an effect on whether proposed workover projects are economically feasible. These factors coupled with the uncertainty of future oil, gas and NGL prices, increase the margin of error inherent in estimating future production and operating costs. Given these uncertainties, Devon estimates that 1997's total production and operating costs will be between $75 million and $87 million.

Depreciation, Depletion and Amortization The 1997 DD&A rate will depend on various factors. Most notable among such factors are the amount of proved reserves that could be added from drilling or acquisition efforts in 1997 compared to the costs incurred for such efforts, and the revisions to Devon's year-end 1996 reserve estimates which will be made during 1997.

The DD&A rate as of the beginning of 1997 was $3.76 per Boe. This rate includes the effect of the December 31, 1996, acquisition of the KMG-NAOS Properties. Conversely, the 1996 yearly rate of $3.88 per Boe did not reflect the effect of these properties. Assuming a 1997 rate of between $3.80 per Boe and $4.20 per Boe, 1997 DD&A expense (including approximately $2.5 million of non-oil and gas property related DD&A) is expected to be $76 million to $84 million.

General and Administrative Expenses Devon's general and administrative expenses include the costs of many different goods and services used in support of the company's business. These goods and services are subject to general price level increases or decreases. In addition, Devon's G&A expenses vary with the company's level of activity and the related staffing needs as well as with the amount of professional services required during any given period. The addition of the KMG-NAOS Properties will increase Devon's general level of activity as well as its staffing requirements during 1997. Should the company's anticipated needs or the prices of the required goods and services differ significantly from the company's expectations, actual G&A expenses could vary materially from the estimate. Given these limitations, G&A expenses are expected to be between $12 million and $14 million in 1997.

Interest Expense Devon's management expects to fund substantially all of its anticipated expenditures during 1997 with working capital and internally generated cash flow. Should Devon's actual capital expenditures or internally generated cash flow vary significantly from expectations, interest expense could differ materially from the following estimate. Given this limitation, interest expense is expected to be less than $1 million in 1997.

Distributions on TCP Securities TCP Securities are convertible into common shares of Devon at the option of the holder. Should any of the holders of the TCP Securities elect to convert during 1997, it would reduce the amount of required distributions. Assuming all $149.5 million of TCP Securities are outstanding for the entire year, Devon will make $9.7 million of distributions in 1997.

Income Taxes Devon expects its financial income tax rate in 1997 to be between 38% and 42%. Regardless of the level of pre-tax earnings reported for financial purposes, Devon will have a minimum of approximately $2.5 million of financial income tax expense due to various aspects of the 1994 Alta Merger, the San Juan Basin Transaction and the KMG-NAOS acquisition. Therefore, if the actual amount of 1997 pre-tax earnings differs materially from what Devon currently expects, the actual financial income tax rate for 1997 could fall outside of the expected rate of 38% to 42%. Also, based on its current expectations of 1997 taxable income, Devon anticipates its current portion of 1997 income taxes will be between $9 million and $13 million. However, revenue and earnings fluctuations could easily make these tax estimates obsolete.

Capital Expenditures 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 the company's price expectations for its future production change significantly, the company may accelerate or defer some projects. Thus, Devon would increase or decrease total 1997 capital expenditures. In addition, if the actual cost of the budgeted items varies significantly from the amount anticipated, actual capital expenditures could vary materially from Devon's estimate.

Though Devon has completed at least one major acquisition in each of the last several 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.

Given these limitations, Devon expects its 1997 capital expenditures for drilling and development efforts to total between $120 million and $135 million, including $8 million to $11 million in Canada. (Canadian amounts are expressed in U.S. dollars, using the year-end 1996 exchange rate of $0.73 U.S. dollar to $1.00 Canadian dollar.) Devon expects to spend $50 million to $65 million in 1997 for drilling, facilities and waterflood costs related to reserves classified as proved as of year-end 1996. Devon also plans to spend another $15 million to $20 million on new, higher risk/reward projects.

Other Cash Uses Devon's management expects the policy of paying a quarterly dividend to continue. With the current $0.05 per share quarterly dividend rate and 32.1 million shares of common stock outstanding, 1997 dividends are expected to approximate $6.4 million.

Capital Resources and Liquidity The estimated future drilling and development activities are expected to be funded through a combination of working capital and net cash provided by operations. The amount of net cash to be provided by operating activities in 1997 is uncertain due to the factors affecting revenues and expenses cited above. However, Devon considers its capital resources to be more than adequate to fund its anticipated capital expenditures.

Based on the expected level of 1997's capital expenditures and net cash provided by operations, Devon does not expect to rely on its credit lines to fund a material portion of its capital expenditures. However, if significant acquisitions or other unplanned capital requirements arise during the year, Devon could utilize its credit lines. The unused portion of these credit lines at the end of 1996 consisted of $252 million of long-term credit facilities, and a $12.5 million (Canadian dollars) demand facility for Devon's new Canadian operations. If so desired, Devon believes that its lenders would increase its credit lines to at least $450 million to $500 million. However, the company does not desire nor anticipate a need to increase its credit lines above their current levels. In fact, to lower its borrowing costs, Devon may reduce its credit lines in 1997 until a need for significant capital arises.

Impact of Recently Issued Accounting Standards Not Yet Adopted In June, 1996, the Financial Accounting Standards Board issued Statement of Financial Accounting Standard No. 125, "Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities." SFAS No. 125 is effective for certain transfers and servicing of financial assets and extinguishment of liabilities occurring after December 31, 1996. It is effective for other transfers of financial assets occurring after December 31, 1997. It is to be applied prospectively. SFAS No. 125 provides accounting and reporting standards for transfers and servicing of financial assets and extinguishment of liabilities based on consistent application of a financial-components approach that focuses on control. It distinguishes transfers of financial assets that are sales from transfers that are secured borrowings. Management of Devon does not expect that adoption of SFAS No. 125 will have a material impact on Devon's financial position or results of operations.

In October, 1996, the American Institute of Certified Public Accountants issued Statement of Position (SOP) 96-1, "Environmental Remediation Liabilities." SOP 96-1 was adopted by Devon on January 1, 1997. It requires, among other things, that environmental remediation liabilities be accrued when the criteria of SFAS No. 5, "Accounting for Contingencies," have been met. SOP 96-1 also provides guidance with respect to the measurement of the remediation liabilities. Such accounting is consistent with Devon's current method of accounting for environmental remediation costs. Therefore, adoption of SOP 96-1 will not have a material impact on Devon's financial position or results of operations.

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 is immaterial.

Independent Auditors' Report

The Board of Directors and Stockholders
Devon Energy Corporation:

We have audited the consolidated financial statements of Devon Energy Corporation and subsidiaries as listed in the accompanying index. 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 generally accepted auditing standards. 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, 1996, 1995 and 1994, and the results of their operations and their cash flows for the years then ended, in conformity with generally accepted accounting principles.

KPMG Peat Marwick LLP

Oklahoma City, Oklahoma
February 7, 1997

DEVON ENERGY CORPORATION AND SUBSIDIARIES
Consolidated Balance Sheets

	December 31, 1996	1995	1994
Assets			
Current assets:			
Cash and cash equivalents	$ 9,401,350	8,897,891	8,336,371
Accounts receivable (Note 5)	29,580,306	14,400,295	15,626,799
Inventories	2,103,486	605,263	534,326
Prepaid expenses	688,752	222,135	564,371
Deferred income taxes (Note 8)	1,600,000	749,000	262,000
Total current assets	43,373,894	24,874,584	25,323,867
Property and equipment, at cost, based on the full cost method of accounting for oil and gas properties (Note 6)	974,805,756	631,437,904	523,941,141
Less accumulated depreciation, depletion and amortization	281,959,410	239,619,167	202,634,961
	692,846,346	391,818,737	321,306,180
Other assets	10,030,560	4,870,796	4,817,489
Total assets	$746,250,800	421,564,117	351,447,536
Liabilities and stockholders' equity			
Current liabilities:			
Accounts payable:			
Trade	4,861,428	3,868,458	6,394,897
Revenues and royalties due to others	10,569,960	7,322,418	7,398,199
Income taxes payable	4,705,447	1,364,070	-
Accrued expenses	3,503,420	3,003,943	3,225,493
Total current liabilities	23,640,255	15,558,889	17,018,589
Revenues and royalties due to others	1,053,270	816,412	1,383,135
Other liabilities (Notes 3 and 11)	10,325,999	8,623,057	-
Long-term debt (Note 7)	8,000,000	143,000,000	98,000,000
Deferred revenue	205,859	72,761	1,299,947
Deferred income taxes (Note 8)	81,121,000	34,452,000	27,340,000
Company-obligated mandatorily redeemable convertible preferred securities of subsidiary trust holding solely 6.5% convertible junior subordinated debentures of Devon Energy Corporation (Note 9)	149,500,000	-	-
Stockholders' equity (Note 10):			
Preferred stock of $1.00 par value. Authorized 3,000,000 shares; none issued	-	-	-
Common stock of $.10 par value. Authorized 400,000,000 shares; issued 32,141,295 in 1996, 22,111,896 in 1995 and 22,050,996 in 1994	3,214,130	2,211,190	2,205,100
Additional paid-in capital	388,090,930	167,430,347	166,654,305
Retained earnings	81,099,357	49,399,461	37,546,460
Total stockholders' equity	472,404,417	219,040,998	206,405,865
Commitments and contingencies (Notes 11 and 12)			
Total liabilities and stockholders' equity	$746,250,800	421,564,117	351,447,536

See accompanying notes to consolidated financial statements.

DEVON ENERGY CORPORATION AND SUBSIDIARIES
Consolidated Statements of Operations

	Year Ended December 31, 1996	1995	1994
Revenues			
Oil sales	$ 80,142,073	55,289,819	38,086,076
Gas sales	68,049,478	50,732,158	56,371,452
Natural gas liquids sales	14,366,771	6,403,663	4,908,126
Other	1,458,562	877,185	1,407,305
Total revenues	164,016,884	113,302,825	100,772,959
Costs and expenses			
Lease operating expenses	31,568,428	27,288,755	24,520,757
Production taxes	10,657,814	6,832,507	6,899,743
Depreciation, depletion and amortization (Note 6)	43,361,029	38,089,783	34,132,150
General and administrative expenses	9,101,429	8,418,739	8,424,687
Interest expense	5,276,527	7,051,142	5,438,911
Distributions on preferred securities of subsidiary trust (Note 9)	4,753,125	-	-
Total costs and expenses	104,718,352	87,680,926	79,416,248
Earnings before income taxes	59,298,532	25,621,899	21,356,711
Income tax expense (Note 8)			
Current	6,709,000	4,495,000	415,000
Deferred	17,789,000	6,625,000	7,197,000
Total income tax expense	24,498,000	11,120,000	7,612,000
Net earnings	$ 34,800,532	14,501,899	13,744,711
Net earnings per average common share outstanding (Note 1):			
Assuming no dilution	$1.57	0.66	0.64
Assuming full dilution	$1.52	0.66	0.64
Weighted average common shares outstanding	22,159,507	22,073,550	21,551,581

See accompanying notes to consolidated financial statements.

DEVON ENERGY CORPORATION AND SUBSIDIARIES
Consolidated Statements of Stockholders' Equity

	Year Ended December 31, 1996	1995	1994
Common stock			
Balance, beginning of year	$ 2,211,190	2,205,100	2,084,232
Par value of common shares issued	1,002,940	6,090	120,868
Balance, end of year	3,214,130	2,211,190	2,205,100
Additional paid-in capital			
Balance, beginning of year	167,430,347	166,654,305	144,403,743
Common shares issued, net of issuance costs	220,660,583	776,042	22,250,562
Balance, end of year	388,090,930	167,430,347	166,654,305
Retained earnings			
Balance, beginning of year	49,399,461	37,546,460	26,411,572
Dividends	(3,100,636)	(2,648,898)	(2,609,823)
Net earnings	34,800,532	14,501,899	13,744,711
Balance, end of year	81,099,357	49,399,461	37,546,460
Total stockholders' equity, end of year	$472,404,417	219,040,998	206,405,865

See accompanying notes to consolidated financial statements.

DEVON ENERGY CORPORATION AND SUBSIDIARIES
Consolidated Statements of Cash Flows

	Year Ended December 31, 1996	1995	1994
Cash flows from operating activities			
Net earnings	$ 34,800,532	14,501,899	13,744,711
Adjustments to reconcile net earnings to net cash provided by operating activities:			
Depreciation, depletion and amortization	43,361,029	38,089,783	34,132,150
(Gain) loss on sale of assets	(3,930)	273,238	(27,086)
Deferred income taxes	17,789,000	6,625,000	7,197,000
Changes in assets and liabilities net of effects of acquisitions of businesses (Note 2):			
(Increase) decrease in:			
Accounts receivable	(15,470,528)	1,213,877	123,388
Inventories	(176,286)	(70,937)	181,475
Prepaid expenses	(466,617)	342,236	712
Other assets	(1,032,653)	677,238	(489,648)
Increase (decrease) in:			
Accounts payable	3,370,474	(430,736)	(8,896,674)
Income taxes payable	3,341,377	1,364,070	(467,962)
Accrued expenses	399,477	(221,550)	997,645
Revenues and royalties due to others	236,858	(566,723)	(62,748)
Long-term other liabilities	519,978	705,636	-
Deferred revenue	133,098	(1,227,186)	(49,127)
Net cash provided by operating activities	86,801,809	61,275,845	46,383,836
Cash flows from investing activities			
Proceeds from sale of property and equipment	4,037,480	9,427,401	4,649,257
Capital expenditures	(98,854,846)	(117,593,897)	(35,619,968)
Payments made for acquisition of business (Note 2)	-	(2,391,484)	(42,397,463)
Net cash used in investing activities	(94,817,366)	(110,557,980)	(73,368,174)
Cash flows from financing activities			
Proceeds from borrowings on revolving line of credit	29,000,000	52,000,000	32,500,000
Principal payments on revolving line of credit	(164,000,000)	(7,000,000)	(14,500,000)
Issuance of common stock, net of issuance costs	577,483	782,132	380,244
Issuance of preferred securities of subsidiary trust, net of issuance costs	144,665,205	-	-
Dividends paid on common stock	(3,100,636)	(2,648,898)	(2,609,823)
Increase in long-term other liabilities (Note 3)	1,376,964	6,710,421	-
Net cash provided by financing activities	8,519,016	49,843,655	15,770,421
Net increase (decrease) in cash and cash equivalents	503,459	561,520	(11,213,917)
Cash and cash equivalents at beginning of year	8,897,891	8,336,371	19,550,288
Cash and cash equivalents at end of year	$ 9,401,350	8,897,891	8,336,371

See accompanying notes to consolidated financial statements.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

Notes to Consolidated Financial Statements December 31, 1996, 1995 and 1994

1. Summary of Significant Accounting Policies

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

Basis of Presentation and Principles of Consolidation

Devon is engaged primarily in oil and gas exploration, development and production, and the acquisition of producing properties. Such activities are primarily in the states of New Mexico, Texas, Oklahoma, Wyoming and Louisiana. Effective December 31, 1996, Devon began operations in Alberta, Canada. Devon's share of the assets, liabilities, revenues and expenses of affiliated partnerships and the accounts of its wholly-owned subsidiaries are included in the accompanying consolidated financial statements. All significant intercompany accounts and transactions have been eliminated in consolidation.

Use of Estimates in the Preparation of Financial Statements

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

Inventories

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

Property and Equipment

Devon follows the full cost method of accounting for its oil and gas properties. Accordingly, all costs incidental to the acquisition, exploration and development of oil and gas properties, including costs of undeveloped leasehold, dry holes and leasehold equipment, are capitalized. Net capitalized costs are limited to the estimated future net revenues, discounted at 10% per annum, from proved oil, natural gas and natural gas liquids reserves. Such limitations are imposed separately for Devon's oil and gas properties in the United States and Canada. Capitalized costs are depleted by an equivalent unit-of-production method, converting gas and natural gas liquids to oil at the ratio of one barrel ("Bbl") of oil to six thousand cubic feet ("Mcf") of natural gas and one barrel of oil to 42 gallons of natural gas liquids. 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.

Devon adopted the provisions of SFAS No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed Of," on January 1, 1996. SFAS No. 121 requires that long-lived assets and certain identifiable intangibles be reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Due to Devon's use of the full cost method of accounting for its oil and gas properties, SFAS No. 121 does not apply to Devon's oil and gas property assets which comprise approximately 97% of Devon's net property and equipment. Accordingly, the adoption of SFAS No. 121 did not have an impact on Devon's financial position or results of operations in 1996.

Depreciation and amortization of other property and equipment, including leasehold improvements, are provided using the straight-line method based on estimated useful lives from 3 to 39 years.

Deferred Revenue

Deferred revenue at the end of 1996 consists primarily of the unrecognized gain from the termination of an interest rate swap agreement. In prior years, deferred revenue included primarily funds received under take-or-pay provisions of certain gas contracts, which provided for recovery by the paying party of certain volumes of gas.

Gas Balancing

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

Devon follows the sales method of accounting for gas imbalances. A liability is recorded only if 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.

Stock Options

On January 1, 1996, Devon adopted SFAS No. 123, "Accounting for Stock-Based Compensation," which permits entities to recognize over the vesting period the fair value of all stock-based awards on the date of grant. Alternatively, SFAS No. 123 also allows entities to continue to apply provisions of APB No. 25, "Accounting for Stock Issued to Employees," whereby compensation expense is recorded on the date of grant only if the current market price of the underlying stock exceeds the exercise price. Companies which continue to apply the provisions of APB No. 25 are required by SFAS No. 123 to disclose pro forma net earnings and net earnings per share for employee stock option grants made in 1995 and future years as if the fair-value-based method defined in SFAS No. 123 had been applied. Devon has elected to continue to apply the provisions of APB No. 25, and has provided the pro forma disclosures required by SFAS No. 123 in Note 10.

Major Purchasers

During 1996, there was one purchaser, Aquila Energy Marketing Corporation ("Aquila"), who accounted for over 10% of Devon's gas sales. Aquila accounted for 45% of Devon's 1996 gas sales. During 1995, there were two purchasers who accounted for over 10% of Devon's gas sales. These two purchasers and their respective share of gas sales were: Aquila - 31%; and Enron Gas Marketing, Inc. ("Enron") - 16%. During 1994, there were three purchasers who accounted for over 10% of Devon's gas sales. These three purchasers and their respective share of gas sales were: Aquila - 21%; Enron - 19%; and Meridian Oil Trading, Inc. - 18%.

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 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.

General and Administrative Expenses

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

Net Earnings Per Common Share

Net earnings per common share assuming no dilution are based upon the weighted average number of shares of common stock outstanding during the year. Stock options have been excluded since they would not have had a significant dilutive effect, and the Trust Convertible Preferred Securities issued in 1996 are excluded as they are not common stock equivalents.

For 1996, net earnings per common share assuming full dilution is based upon the adjusted amount of net earnings and the adjusted number of common shares outstanding assuming the Trust Convertible Preferred Securities had been converted to common stock as of their issuance date in July 1996. The fully diluted per share amount in 1996 also includes the effect of Devon's outstanding stock options as calculated using the treasury stock method. The 1996 adjusted net earnings used for the fully diluted calculation was $37.8 million, and the adjusted number of common shares was 24,860,910.

No fully diluted per share amounts are presented for 1995 and 1994 due to the insignificant dilutive effect of the stock options outstanding.

Dividends

Dividends on common stock were paid in 1994, 1995 and the first three quarters of 1996 at a per share rate of $0.03 per quarter. The dividend rate was increased to $0.05 per share for the fourth quarter of 1996.

Fair Value of Financial Instruments

Devon's only financial instruments for which the fair value differs materially from the carrying value are the interest rate swap discussed in Note 7 and the Trust Convertible Preferred Securities discussed in Note 9. The fair value and the carrying value for all other financial instruments (cash and equivalents, accounts receivable, accounts payable and long-term debt) are approximately equal. Such equality is due to the short-term nature of the current assets and liabilities and the fact that the interest rates paid on Devon's long-term debt are set for periods of three months or less.

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.

In October, 1996, the American Institute of Certified Public Accountants issued Statement of Position (SOP) 96-1, "Environmental Remediation Liabilities." SOP 96-1 was adopted by Devon on January 1, 1997. It requires, among other things, that environmental remediation liabilities be accrued when the criteria of SFAS No. 5, "Accounting for Contingencies," have been met. SOP 96-1 also provides guidance with respect to the measurement of the remediation liabilities. Such accounting is consistent with Devon's method of accounting for environmental remediation costs. Therefore, adoption of SOP 96-1 will not have a material impact on Devon's financial position or results of operations.

2. Acquisitions and Pro Forma Information

On December 31, 1996, Devon acquired all of Kerr- McGee Corporation's ("Kerr-McGee") North American onshore oil and gas exploration and production business and properties (the "KMG-NAOS Properties"). As consideration, Devon issued 9,954,000 shares of its common stock to Kerr-McGee. The acquisition was made pursuant to an October 17, 1996, agreement and plan of merger among Devon, Kerr-McGee and certain of their subsidiaries.

Devon recorded the KMG-NAOS Properties at approximately $221.6 million. Such value was based on the value of the shares of Devon common stock issued as determined pursuant to generally accepted accounting principles. An additional $28.0 million was allocated to the KMG-NAOS Properties for the deferred income tax liability created as a result of the substantially tax-free nature of the transaction to Kerr-McGee. Excluding the additional deferred tax liability, the amount recorded for the KMG-NAOS Properties includes approximately $191.7 million allocated to proved oil and gas reserves, $29.0 million allocated to undeveloped leasehold acquired and $0.9 million allocated to inventories and other assets acquired. Including the additional $28.0 million of deferred tax liability, $214.2 million was allocated to proved reserves and $34.5 million to undeveloped leasehold.

Estimated proved reserves associated with the KMG- NAOS Properties as of December 31, 1996, were 47 million barrels of oil equivalent ("MMBoe") in the United States and 15 MMBoe in Canada. These reserves are approximately 36% oil and natural gas liquids and 64% natural gas. Included in the acquired reserves were certain proved undeveloped reserves, for which Devon expects to incur approximately $6 million of future capital costs. The United
States assets acquired are located predominantly in the Rocky Mountain, Permian Basin and Mid-Continent areas of the country. All of these areas were already core areas of Devon's operations. (The quantities of proved reserves and the estimated development costs stated in this paragraph are unaudited.)

On December 18, 1995, Devon acquired additional interests in certain of its Wyoming oil and natural gas properties and a gas processing plant (the "Worland Properties") for approximately $50.3 million. The acquisition was primarily funded with $46.0 million of borrowings from Devon's credit lines. Approximately $46.3 million of the purchase price was allocated to proved oil, gas and natural gas liquids reserves and the plant. The remaining $4.0 million of the purchase price was allocated to undeveloped leasehold.

On February 18, 1994, Devon and Alta Energy Corporation ("Alta") entered into an Agreement and Plan of Merger, as amended on April 13, 1994, whereby Alta was merged into a wholly-owned subsidiary of Devon (the "Alta Merger"). The Alta Merger was consummated on May 18, 1994, at which date the separate existence of Alta ceased. Alta's common stockholders received approximately 1,168,000 shares of Devon common stock and $1.5 million in cash upon consummation of the Alta Merger. Subsequently, in February 1995, former Alta stockholders received an additional cash payment of $2.4 million based upon the post-closing evaluation of the Camille Adams #1 well in Louisiana. Devon also incurred $41.4 million of other costs related to the Alta Merger. This included $31.7 million to acquire Alta's debt from its creditors, $3.0 million to acquire shares of Alta preferred and common stock, $3.8 million loaned to Alta for operating funds, $1.5 million to acquire certain net profits interests from Alta creditors, and $1.4 million for third party costs related to the Alta Merger.

Devon recorded additional deferred tax liabilities of $11.5 million due to the substantially tax-free nature of the Alta Merger to the former Alta stockholders. Excluding the $11.5 million of additional deferred tax liabilities, approximately $69.4 million of the total consideration involved in the Alta Merger was allocated to proved oil and gas reserves. Including the deferred tax liabilities, $80.9 million was allocated to proved oil and gas reserves. The Alta Merger was accounted for by the purchase method of accounting for business combinations. Accordingly, the accompanying 1994 consolidated statement of operations does not include any revenue or expenses associated with Alta prior to the May 18, 1994 closing date.

Pro Forma Information (Unaudited)

The 1996 acquisition of the KMG-NAOS Properties as described above was accounted for by the purchase method of accounting for business combinations. Accordingly, the accompanying 1996 consolidated statement of operations does not include any revenues or expenses associated with the KMG- NAOS Properties. Following are Devon's pro forma results for 1996 assuming the acquisition of the KMG-NAOS Properties occurred on January 1, 1996:

	1996
Revenues	
Oil sales	$148,337,000
Gas sales	125,092,000
Natural gas liquids sales	19,081,000
Other	4,674,000
Total revenues	297,184,000
Costs and expenses	
Lease operating expenses	58,384,000
Production taxes	20,167,000
Depreciation, depletion and amortization	78,310,000
General and administrative expenses	14,101,000
Interest expense	5,277,000
Distributions on preferred securities of subsidiary trust	4,753,000
Total costs and expenses	180,992,000
Earnings before income taxes	116,192,000
Income tax expense	
Current	14,023,000
Deferred	32,721,000
Total income tax expense	46,744,000
Net earnings	$ 69,448,000
Net earnings per average common share outstanding:	
Assuming no dilution	$2.16
Assuming full dilution	$2.08
Weighted average common shares outstanding	32,086,310
Production data	
Oil (Barrels)	7,241,000
Gas (Mcf)	70,925,000
Natural gas liquids (Barrels)	1,304,000

The 1995 acquisition of the Worland Properties described above was accounted for by the purchase method of accounting for business combinations. Accordingly, the accompanying consolidated statements of operations do not include any revenues or expenses related to the Worland Properties prior to the closing date of December 18, 1995. Following are Devon's pro forma 1995 results assuming the acquisition of KMG-NAOS Properties and the Worland Properties both occurred on January 1, 1995:

	1995			
		Pro Forma Effect of		
	Devon Historical	KMG-NAOS Properties	Worland Properties	Devon Pro Forma
Total revenues	$113,303,000	108,279,000	5,349,000	226,931,000
Net earnings	$14,502,000	14,335,000	(1,405,000)	27,432,000
Net earnings per share	$0.66			0.86

3. San Juan Basin Transaction

Effective January 1, 1995, Devon and an unrelated company entered into a transaction covering substantially all of Devon's San Juan Basin coal seam gas properties (the "San Juan Basin Transaction"). These coal seam gas properties represented Devon's largest oil and gas reserve position as of December 31, 1994. The properties' estimated reserves as of year-end
1994 were 199.2 billion cubic feet ("Bcf") of natural gas, or 31% of Devon's 633.2 equivalent Bcf of combined oil and natural gas reserves. In addition to the cash flow and earnings impact
normally associated with oil and gas production, these properties also qualify as a "nonconventional fuel source" under the Internal Revenue Code of 1986. Consequently, gas produced from these properties through the year 2002 qualifies for Section 29 tax credits, which as of year-end 1996 were equal to approximately $1.02 per million Btu ("MMBtu").

The San Juan Basin Transaction involves approximately 186.2 Bcf, or 93%, of the year-end 1994 coal seam gas reserves, and has four major parts associated with it. First, Devon conveyed to the unrelated party 179 Bcf of the properties' reserves. However, for financial reporting purposes, Devon retained all of such reserves and their future production and cash flow through a volumetric production payment and a repurchase option. Second, Devon conveyed outright to the unrelated party 7.2 Bcf of reserves for a sales price of $5.2 million. The reserves and future cash flow associated with this conveyance were not retained by Devon. Third, and the source of the most significant impact of the transaction, Devon receives payments equal to 75% of the Section 29 tax credits generated by the properties. And fourth, Devon retained a 75% reversionary interest in any reserves in excess of the 186.2 Bcf estimated to exist as of December 31, 1994. Each of these parts of the San Juan Basin Transaction, and their effects on Devon's operations, are described in more detail in the following paragraphs.

The production payment retained by Devon is equal to 94.05% of the first 143.4 Bcf of gas produced from the properties, or 134.9 Bcf. As such, Devon continues to record gas sales and associated production and operating expenses and reserves associated with the production payment. Production from the retained production payment is currently estimated to occur over a period of 12 years.

The conveyance of the properties which are not subject to the retained production payment or the repurchase option was accounted for as a sale of oil and gas properties. Accordingly, 7.2 Bcf of gas reserves were removed from total proved reserves, and the $5.2 million of proceeds reduced the book value of oil and gas properties. The conveyance to the third party is limited exclusively to the existing wells drilled as of January 1, 1995. Wells to be drilled in the future, if any, are not included in this transaction.

In addition to receiving 94.05% of the properties' net cash flow through the retained production payment, Devon receives quarterly payments from the third party equal to 75% of the value of the Section 29 tax credits which are generated by production from such properties until the earlier of December 31, 2002, or until the option to repurchase is exercised. For the years ended December 31, 1996 and 1995, Devon received $11.5 million and $13.9 million, respectively, related to the credits. Of these amounts, $10.3 million and $12.8 million were recorded as additional gas sales in 1996 and 1995, respectively, and $1.2 million and $1.1 million were recorded as an addition to liabilities in 1996 and 1995, respectively, as discussed in the following paragraph. Based on the reserves estimated at December 31, 1996, and an assumed annual inflation factor of 2%, Devon estimates it will receive total tax credit payments of approximately $58 million from 1997 through 2002.

Devon has an option to repurchase the properties at any time. The purchase price of such option is equal to the fair market value of the properties at the time the option is exercised, as defined in the transaction agreement, less the production payment balance. At closing, Devon received $5.6 million associated with reserves to be produced subsequent to the term of the production payment. Such amount is included in long-term "other liabilities" on the accompanying balance sheet. Since Devon expects to eventually exercise its option to repurchase the properties, the liability will be increased over time to reflect the option purchase price. As the purchase price increases, a portion of the tax credit payments received by Devon will be added to the liability. As stated above, for the years ended December 31, 1996 and 1995, $1.2 million and $1.1 million, respectively, of the total amount received for tax credit payments were added to the liability, which raised the liability balance to $7.9 million as of December 31, 1996.

Devon has retained a 75% reversionary interest in the properties' reserves in excess, if any, of the 186.2 Bcf of reserves estimated to exist at December 31, 1994. The terms of the transaction provide that the third party will pay 100% of the capital necessary to develop any such incremental reserves for its 25% interest in such reserves. Devon's repurchase option also includes the right to purchase this incremental 25%. However, the $7.9 million of other liabilities recorded as of year-end 1996, does not include any amount related to such reserves.

4. Supplemental Cash Flow Information

Cash payments for interest in 1996, 1995, and 1994 were approximately $5.5 million, $6.7 million and $5.1 million, respectively. Cash payments for federal and state income taxes in 1996, 1995, and 1994 were approximately $3.4 million, $2.2 million and $1.8 million, respectively.

The 1996 acquisition of the KMG-NAOS Properties and the 1994 Alta Merger involved cash and non-cash consideration as presented below:

	1996	1994
Cash payments made	$ -	42,915,845
Value of common stock issued	221,576,040	21,991,084
Liabilities assumed	-	7,192,671
Deferred tax liability created	28,029,000	11,500,000
Fair value of assets acquired	$249,605,040	83,599,600

The above cash payments of $42.9 million in 1994 include approximately $1.4 million of direct costs paid to third parties which were capitalized and allocated to producing oil and gas properties. The cash payments made are reduced in the accompanying 1994 consolidated statement of cash flows by $518,382 of cash acquired in the Alta Merger.

5. Accounts Receivable

The components of accounts receivable included the following:

	December 31, 1996	1995	1994

Oil, gas and natural gas liquids revenue accruals	$24,200,047	11,169,313	10,973,589
Joint interest billings	4,318,764	2,962,037	3,367,493
Income tax refunds due	-	-	959,085
Other	1,461,495	493,945	551,632
	29,980,306	14,625,295	15,851,799
Allowance for doubtful accounts	(400,000)	(225,000)	(225,000)
Net accounts receivable	$29,580,306	14,400,295	15,626,799

6. Property and Equipment

Property and equipment included the following:

	December 31, 1996	1995	1994
Oil and gas properties:			
Subject to amortization	$899,827,749	604,227,702	503,174,488
Not subject to amortization:			
Acquired in 1996	35,141,800	-	-
Acquired in 1995	5,034,942	5,635,170	-
Acquired in 1994	1,001,291	1,001,427	1,451,109
Acquired in 1993	5,204,995	5,556,977	5,556,977
Acquired in 1992	8,113,899	8,257,985	8,561,031
Accumulated depreciation, depletion and amortization	(278,923,340)	(237,385,785)	(200,746,032)
Net oil and gas properties	675,401,336	387,293,476	317,997,573
Other property and equipment	20,481,080	6,758,643	5,197,536
Accumulated depreciation and amortization	(3,036,070)	(2,233,382)	(1,888,929)
Net other property and equipment	17,445,010	4,525,261	3,308,607
Property and equipment, net of accumulated depreciation, depletion and amortization	$ 692,846,346	391,818,737	321,306,180

Depreciation, depletion and amortization expense consisted of the following components:

	Year Ended December 31, 1996	1995	1994
Depreciation, depletion and amortization of oil and gas properties	$41,537,555	36,639,753	32,861,174
Depreciation and amortization of other property and equipment	1,337,420	1,045,978	865,092
Amortization of other assets	486,054	404,052	405,884
Total expense	$43,361,029	38,089,783	34,132,150

7. Long-term Debt

Devon has long-term lines of credit pursuant to which it can borrow up to an amount determined by the banks based on their evaluation of the assets and cash flow (the "Borrowing Base") of Devon. The established Borrowing Base at December 31, 1996, was $260 million. Amounts borrowed under the credit lines bear interest at various fixed rate options which Devon may elect for periods up to 90 days. Such rates are generally less than the prime rate. Devon may also elect to borrow at the prime rate. The average interest rates on the outstanding debt at the end of 1996, 1995 and 1994, were 6.19%, 6.64% and 6.83%, respectively. The loan agreements also provide for a quarterly facility fee equal to .25% per annum.

Debt borrowed under the credit lines is unsecured. No principal payments are required until maturity unless the unpaid balance exceeds the maximum loan amount. The maximum loan amount is equal to the Borrowing Base until August 31, 1999. Thereafter, the maximum loan amount will be reduced by 8.33% every three months until August 31, 2002. The loan agreements contain certain covenants and restrictions, among which are limitations on additional borrowings and annual sales of properties valued at more than $25 million, and working capital and net worth maintenance requirements. At December 31, 1996, Devon was in compliance with such covenants and restrictions.

On December 31, 1996, Devon established a demand revolving operating credit facility with a Canadian bank. This facility is unsecured and will be utilized for general corporate purposes related to Devon's new Canadian operations. The credit line totals $12.5 million Canadian dollars, and interest is charged at the bank's prime rate for loans to Canadian customers. Amounts borrowed are due on demand. However, due to Devon's sources of long-term debt described above, amounts borrowed pursuant to the Canadian credit line are expected to be classified as long-term debt. No amounts were borrowed against the Canadian credit line at year-end 1996.

Devon entered into an interest rate swap agreement in June, 1995, to hedge the impact of interest rate changes on a portion of its long-term debt. The notional amount of the swap agreement was $75 million, and the other party to the agreement was one of Devon's lenders. The swap agreement was accounted for as a hedge. On July 1, 1996, Devon terminated the interest rate swap agreement for a gain of $0.8 million. This gain is being recognized ratably as a reduction to interest expense during the period from July 1, 1996 to June 16, 1998 (the original expiration date of the agreement). Approximately $0.2 million of the gain was recognized in 1996. The fair value of the interest rate swap as of December 31, 1995 was a liability of approximately $1.4 million. The interest rate swap had no carrying value in the accompanying consolidated financial statements.

See Note 9 for a description of certain convertible debentures issued in 1996 to a Devon affiliate.

8. Income Taxes

At December 31, 1996, Devon had the following carryforwards available to reduce future federal and state income taxes:

Types of Carryforward	Years of Expiration	Carryforward Amounts
Net operating loss - federal	1998 - 2008	$14,100,000
Net operating loss - various states	1997 - 2010	$10,000,000
Statutory depletion	No expiration	$ 1,200,000
Minimum tax credit	No expiration	$ 5,600,000

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

Total income tax expense differed from the amounts computed by applying the federal income tax rate to net earnings before income taxes as a result of the following:

	Year Ended December 31, 1996	1995	1994
Federal statutory tax rate	35%	35%	35%
Nonconventional fuel source credits	-	(1)	-
State income taxes	5	4	3
Effect of San Juan Basin Transaction	2	4	-
Other	(1)	1	(2)
Effective income tax rate	41%	43%	36%

The tax effects of temporary differences that gave rise to significant portions of the deferred tax assets and liabilities at December 31, 1996, 1995 and 1994 are presented below:

	December 31, 1996	1995	1994
Deferred tax assets:			
Net operating loss carryforwards	$ 5,314,000	6,082,000	6,127,000
Statutory depletion carryforwards	412,000	2,287,000	3,087,000
Investment tax credit carryforwards	42,000	85,000	813,000
Minimum tax credit carryforwards	5,624,000	5,576,000	2,195,000
Production payments	19,685,000	24,770,000	-
Other	2,613,000	1,966,000	897,000
Total gross deferred tax assets	33,690,000	40,766,000	13,119,000
Less valuation allowance	100,000	100,000	100,000
Net deferred tax assets	33,590,000	40,666,000	13,019,000
Deferred tax liabilities:			
Property and equipment, principally due to differences in depreciation, and the expensing of intangible drilling costs for tax purposes	(113,111,000)	(74,369,000)	(40,097,000)
Net deferred tax liability	$ (79,521,000)	(33,703,000)	(27,078,000)

As shown in the above schedule, Devon has recognized $33.6 million of net deferred tax assets as of December 31, 1996. Such amount consists almost entirely of $11.4 million of various carryforwards available to offset future income taxes, and $19.7 million of net tax basis in production payments. The carryforwards include federal net operating loss carryforwards, the majority of which do not begin to expire until

2006, state net operating loss carryforwards which expire primarily between 1999 and 2003, and the statutory depletion and minimum tax credit carryforwards which have no expiration dates. 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 1997 and 1999. Such expectation is based upon current estimates of taxable income during this period, considering limitations on the annual utilization of these benefits as set forth by federal tax regulations. Significant changes in such estimates caused by variables such as future oil and gas prices or capital expenditures could alter the timing of the eventual utilization of such carryforwards. There can be no assurance that Devon will generate any specific level of continuing taxable earnings. However, management believes that Devon's future taxable income will more likely than not be sufficient to utilize substantially all its tax carryforwards prior to their expiration. A $100,000 valuation allowance has been recorded at December 31, 1996, related to depletion carryforwards acquired in the Alta Merger.

The $19.7 million of deferred tax assets related to production payments is offset by a portion of the deferred tax liability related to the excess financial basis of property and equipment. The income tax accounting for the San Juan Basin Transaction described in Note 3 differs from the financial accounting treatment which is described in such note. For income tax purposes, a gain from the conveyance of the properties was realized, and the present value of the production payments to be received was recorded as a note receivable. For presentation purposes, the $19.7 million represents the tax effect of the difference in accounting for the production payment, less the effect of the taxable gain from the transaction which is being deferred and recognized on the installment basis for income tax purposes.

9. Trust Convertible Preferred Securities

On July 10, 1996, Devon, through its newly-formed affiliate Devon Financing Trust, completed the issuance of $149.5 million of 6.5% trust convertible preferred securities (the "TCP Securities") in a private placement. Devon Financing Trust issued 2,990,000 shares of the TCP Securities at $50 per share. Each TCP Security is convertible at the holder's option into 1.6393 shares of Devon common stock, which equates to a conversion price of $30.50 per share of Devon common stock.

Devon Financing Trust invested the $149.5 million of proceeds in 6.5% convertible junior subordinated debentures issued by Devon (the "Convertible Debentures"). In turn, Devon used the net proceeds from the issuance of the Convertible Debentures to retire debt outstanding under its credit lines.

The sole assets of Devon Financing Trust are the Convertible Debentures. The Convertible Debentures and the related TCP Securities mature on June 15, 2026. However, Devon and Devon Financing Trust may redeem the Convertible Debentures and the TCP Securities, respectively, in whole or in part, on or after June 18, 1999. For the first twelve months thereafter, redemptions may be made at 104.55% of the principal amount. This premium declines proportionally every twelve months until June 15, 2006, when the redemption price becomes fixed at 100% of the principal amount. If Devon redeems any Convertible Debentures prior to the scheduled maturity date, Devon Financing Trust must redeem TCP Securities having an aggregate liquidation amount equal to the aggregate principal amount of Convertible Debentures so redeemed.

Devon has guaranteed the payments of distributions and other payments on the TCP Securities only if and to the extent that Devon Financing Trust has funds available therefor. Such guarantee, when taken together with Devon's obligations under the Convertible Debentures and related indenture and declaration of trust, provide a full and unconditional guarantee of amounts due on the TCP Securities.

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

Devon estimates that the fair value of the TCP Securities as of December 31, 1996 was approximately $196.6 million, as compared to the book value of $149.5 million. This fair value was based on quoted prices at which TCP Securities were purchased and sold on December 31, 1996.

10. Stockholders' Equity

The authorized capital stock of Devon consists of 400 million shares of common stock, par value $.10 per share (the "Common Stock"), and three million shares of preferred stock, par value $1.00 per share (the "Preferred Stock"). 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.

Devon's Board of Directors has designated 150,000 shares of the Preferred Stock as Series A Junior Participating Preferred Stock (the "Series A Preferred Stock") in connection with the adoption of the share rights plan described later in this note. At December 31, 1996, there were no shares of Series A Preferred Stock issued or outstanding. The Series A 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 Preferred Stock. Holders of the Series A 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 Preferred Stock is neither redeemable nor convertible. The Series A 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 two stock option plans adopted in 1988 and 1993 ("the 1988 Plan" and "the 1993 Plan"). Options granted under the 1988 Plan remain exercisable by the employees owning such options, but no new options will be granted under the 1988 Plan. At December 31, 1996, 15 participants held the 303,400 options outstanding under the 1988 Plan.

Effective June 7, 1993, Devon adopted the 1993 Plan and reserved one million shares of Common Stock for issuance thereunder. Twenty-two employees were eligible to participate in the 1993 Plan at year-end 1996.

The exercise price of incentive stock options granted under the 1993 Plan may not be less than the estimated fair market value of the stock at the date of grant, plus 10% if the grantee owns or controls more than 10% of the total voting stock of Devon prior to the grant. The exercise price of nonqualified options granted under the 1993 Plan may not be less than 75% of the fair market value of the stock on the date of grant. Options granted are exercisable during a period established for each grant, which period may not exceed 10 years from the date of grant. Under the 1993 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 1993 Plan is administered by a committee comprised of non-management members of the Board of Directors. The 1993 Plan expires on April 25, 2003. As of December 31, 1996, 23 participants held the 898,600 options outstanding under the 1993 Plan. There were 88,700 options available for future grants as of December 31, 1996.

A summary of the status of Devon's stock option plans as of December 31, 1994, 1995 and 1996, 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
Balance at December 31, 1993	482,700	$16.521	300,000	$14.848
Options granted	436,000	$20.736		
Options exercised	(40,800)	$9.355		
Balance at December 31, 1994	877,900	$18.947	485,000	$17.423
Options granted	219,000	$23.875		
Options exercised	(60,900)	$12.843		
Options forfeited	(7,100)	$20.105		
Balance at December 31, 1995	1,028,900	$20.349	688,800	$19.744
Options granted	248,500	$32.358		
Options exercised	(75,400)	$12.909		
Balance at December 31, 1996	1,202,000	$23.299	823,500	$21.783

The weighted average fair values of options granted during 1996 and 1995 were $12.97 and $9.89, respectively. The fair value of each option grant was estimated for disclosure purposes only on the date of grant using the Binomial Option Pricing Model with the following assumptions for 1996 and 1995, respectively: risk-free interest rates of 6.3% and 5.5%; dividend yields of 0.6% and 0.5%; expected lives of 5 and 5 years; and volatility of the price of the underlying common stock of 33.9% and 38.1%.

The following table summarizes information about Devon's stock options which were outstanding, and those which were exercisable, as of December 31, 1996:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number Outstanding	Weighted Average Remaining Life	Weighted Average Exercise Price	Number Exercisable	Weighted Average Exercise Price
$8-$14	108,600	4.6 years	$9.662	108,600	$9.662
$18-$21	205,700	7.9 years	$18.088	146,400	$18.092
$23-$26	644,200	7.7 years	$23.784	487,800	$23.816
$32-$33	243,500	10.0 years	$32.500	80,700	$32.500
	1,202,000	7.9 years	$23.299	823,500	$21.783

Had Devon elected the fair value provisions of SFAS No. 123 and recognized compensation expense based on the fair value of the stock options granted as of their grant date, Devon's 1996 and 1995 pro forma net earnings and pro forma net earnings per share would have differed from the amounts actually reported as shown in the table below. The pro forma amounts shown below do not include the effects of stock options granted prior to January 1, 1995. The pro forma effects shown below may not be representative of the effects reported in future years.

	Year Ended December 31, 1996	1995
Net earnings:		
As reported	$34,800,532	14,501,899
Pro forma	$34,016,571	13,540,052
Net earnings per share:		
As reported:		
Assuming no dilution	$1.57	0.66
Assuming full dilution	$1.52	0.66
Pro forma:		
Assuming no dilution	$1.54	0.61
Assuming full dilution	$1.49	0.61

Share Rights Plan

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

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

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

11. Retirement Plans

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

Effective January 1, 1995, Devon has a separate defined benefit retirement plan (the "Supplementary Plan") which is non-contributory and includes only certain employees whose benefits under the Basic Plan are limited by federal income tax regulations. The Supplementary Plan's benefits are based on the employee's years of service and compensation. Devon's funding policy for the Supplementary Plan is to fund the benefits as they become payable. Rights to amend or terminate the Supplementary Plan are retained by Devon.

The following table sets forth the aggregate funded status of the Basic Plan and related amounts recognized in Devon's balance sheets:

	December 31, 1996	1995	1994
Actuarial present value of benefit obligations:			
Accumulated benefit obligation:			
Vested	$(3,619,000)	(3,500,000)	(2,648,000)
Nonvested	(741,000)	(654,000)	(282,000)
Total	$(4,360,000)	(4,154,000)	(2,930,000)
Projected benefit obligation for service rendered to date	(5,122,000)	(4,782,000)	(3,378,000)
Plan assets at fair value, primarily investments in mutual funds	5,022,000	4,227,000	3,252,000
Plan assets less than projected benefit obligation	(100,000)	(555,000)	(126,000)
Unrecognized prior service cost (benefit)	(131,000)	(154,000)	(176,000)

Unrecognized net loss from past experience different from that assumed, and effects of changes in assumptions		519,000	921,000	225,000
Prepaid (accrued) pension expense	$	288,000	212,000	(77,000)

The following table sets forth the aggregate funded status of the Supplementary Plan and related amounts recognized in Devon's balance sheet as of December 31, 1996 and 1995:

	December 31, 1996	1995
Actuarial present value of benefit obligations:		
Accumulated benefit obligation:		
Vested	$(1,960,000)	(1,658,000)
Nonvested	(279,000)	(255,000)
Total	$(2,239,000)	(1,913,000)
Projected benefit obligation for service rendered to date	(2,907,000)	(2,245,000)
Plan assets at fair value	-	-
Plan assets less than projected benefit obligation	(2,907,000)	(2,245,000)
Unrecognized prior service cost	1,235,000	1,354,000
Unrecognized net loss from past experience different from that assumed, and effects of changes in assumptions	446,000	185,000
Accrued pension expense	(1,226,000)	(706,000)
Additional minimum liability	(1,013,000)	(1,207,000)
Total pension liability	$(2,239,000)	(1,913,000)

The $2.2 million and $1.9 million total pension liability of the Supplementary Plan as of December 31, 1996 and 1995, respectively, are included in long-term other liabilities on the accompanying consolidated balance sheets. The additional minimum liabilities of $1.0 million and $1.2 million at year-end 1996 and 1995, respectively, are offset by intangible assets of $1.0 million in 1996 and $1.2 million in 1995. These intangible assets are included in other assets on the balance sheets.

Net pension expense for Devon's two defined benefit plans included the following components:

	Year Ended December 31, 1996	1995	1994
Service cost - benefits earned during the period	$ 557,000	362,000	277,000
Interest cost on projected benefit obligation	569,000	446,000	284,000
Actual return on plan assets	(453,000)	(536,000)	(20,000)
Net amortization and deferral	231,000	345,000	(231,000)
Net periodic pension expense	$ 904,000	617,000	310,000

The weighted average discount rate used in determining the actuarial present value of the projected benefit obligation in 1996, 1995 and 1994 was 7.5%, 7.25% and 8.5%, respectively. The rate of increase in future compensation levels was 5% for all three years. The expected long-term rate of return on assets was 8.5%, 8.5% and 8% in 1996, 1995 and 1994, respectively.

Devon has a 401(k) Incentive Savings Plan which covers all 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 $188,000, $170,000 and $158,000 for the years ended December 31, 1996, 1995 and 1994, respectively.

12. 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 after consideration of recorded accruals.

The majority of Devon's sales of nonconventional gas from the San Juan Basin are subject to federal royalties administered and collected by the Minerals Management Service ("MMS"). In determining royalties payable to the MMS, Devon has followed the industry practice of reducing the gas sales price for certain permitted costs related to the transportation of gas produced and CO_2 removal. In 1995, the MMS issued new policies which would increase Devon's share of federal royalties for nonconventional gas produced and sold in the San Juan Basin for the years 1990 through 1996, and for future years as well. In early 1997, the MMS asserted a claim for additional royalties. While the specific claim only covers 17 months of the seven-year period in question, the MMS has requested Devon to calculate and pay additional royalties for the entire seven-year period using methods and procedures consistent with the calculation for the 17 months. Devon has not determined whether it agrees with the methods and procedures used by the MMS in its calculations, and Devon intends to vigorously contest any claim for excessive additional federal royalties through available administrative and judicial processes. However, Devon has accrued an estimate of additional federal royalties related to its share of gas produced from 1990 through 1996. Devon's management, in consultation with legal counsel, believes adequate provision has been made for any additional federal royalties due and related interest. The amount accrued represents Devon's best estimate based on Devon's interpretation of the new policies issued and all other related information available to Devon. It is possible that a different interpretation of the policies and related facts could result in an assessment higher than what Devon has accrued. However, Devon's management does not believe that the amount of possible assessments above that already accrued would be material.

In a matter unrelated to the MMS issue discussed above, the State of New Mexico on December 29, 1995, assessed Devon and other producers of gas from the San Juan Basin a "natural gas processors tax." Devon's tax assessment for the years 1990 through 1995 was approximately $0.6 million, and the state also assessed another $0.3 million of penalties and interest. All of the assessment relates to nonconventional gas. Devon paid these assessments in January 1996, as well as an additional $0.2 million for 1996 taxes which were paid monthly throughout the year, so that it could begin the necessary procedures of applying for a refund. This tax historically was paid by the owners of natural gas processing plants, not the gas producers, and was assessed for the privilege of processing natural gas. While Devon's nonconventional gas is purified through a plant prior to the actual sales point, such purification is only for the purpose of removing CO_2. Also, Devon does not own an interest in such plant. For these and other reasons, Devon does not believe the assessment of the additional tax and the related penalties and interest is valid. If the amount paid is not refunded through the normal administrative processes available, Devon intends to file a suit asking that the assessments be reversed. At this time, it is not possible to determine the eventual outcome of this matter. Devon has not expensed in its financial statements the taxes, penalties and interest paid, but rather has recorded the $1.1 million total as a receivable.

The following is a schedule by year of future minimum rental payments required under operating leases that have initial or remaining noncancelable lease terms in excess of one year as of December 31, 1996:

Year ending December 31,	
1997	$233,000
1998	183,000
1999	138,000
2000	123,000
Total minimum lease payments required	$677,000

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

1996	$572,177
1995	$546,388
1994	$521,769

13. Oil and Gas Operations

Costs Incurred

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

	Total Year Ended December 31, 1996	1995	1994
Property acquisition costs:			
Proved, excluding deferred income taxes	$199,655,000	47,316,000	70,376,000
Deferred income taxes	22,557,000	-	11,500,000
Total proved, including deferred income taxes	$222,212,000	47,316,000	81,876,000
Unproved, excluding deferred income taxes	$29,673,000	4,529,000	1,797,000
Deferred income taxes	5,472,000	-	-
Total unproved, including deferred income taxes	35,145,000	4,529,000	1,797,000
Exploration costs	$ 2,708,000	7,174,000	5,194,000
Development costs	$ 73,468,000	56,253,000	26,268,000

	Domestic Year Ended December 31, 1996	1995	1994
Property acquisition costs:			
Proved, excluding deferred income taxes	$150,546,000	47,316,000	70,376,000
Deferred income taxes	15,257,000	-	11,500,000

Total proved, including deferred income taxes	$165,803,000	47,316,000	81,876,000
Unproved, excluding deferred income taxes	$26,073,000	4,529,000	1,797,000
Deferred income taxes	5,472,000	-	-
Total unproved, including deferred income taxes	31,545,000	4,529,000	1,797,000
Exploration costs	$ 2,708,000	7,174,000	5,194,000
Development costs	$ 73,468,000	56,253,000	26,268,000

	Canada Year Ended December 31,		
	1996	1995	1994
Property acquisition costs:			
Proved, excluding deferred income taxes	$ 49,109,000	-	-
Deferred income taxes	7,300,000	-	-
Total proved, including deferred income taxes	$ 56,409,000	-	-
Unproved	$ 3,600,000	-	-
Exploration costs	$ -	-	-
Development costs	$ -	-	-

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 above tables, were $2.9 million, $2.7 million and $2.3 million in the years 1996, 1995 and 1994, respectively.

Due to the substantially tax-free nature of the acquisition of the KMG-NAOS properties to Kerr-McGee, and of the 1994 Alta Merger to the former Alta stockholders, Devon recorded additional deferred tax liabilities of $28.0 million related to the KMG-NAOS acquisition and $11.5 million related to the Alta Merger. As shown in the above tables, the deferred tax liabilities caused an additional $22.5 million and $11.5 million to be allocated to proved oil and gas reserves in 1996 and 1994, respectively, and an additional $5.5 million to be allocated to unproved properties in 1996.

Results of Operations for Oil and Gas Producing Activities

The following tables include revenues and expenses associated directly with Devon's oil and gas producing activities. They do not include any allocation of Devon's interest costs or general corporate overhead and, therefore, are not necessarily indicative of the contribution to net earnings of Devon's oil and gas operations. Income tax expense has been calculated by applying statutory income tax rates to oil and gas sales after deducting costs, including depreciation, depletion and amortization and after giving effect to permanent differences. For the three year period ended December 31, 1996, Devon had no oil and gas producing activities outside the United States.

	Year Ended December 31,		
	1996	1995	1994
Oil, gas and natural gas liquids sales	$162,558,000	112,425,000	99,366,000
Production and operating expenses	(42,226,000)	(34,121,000)	(31,421,000)
Depreciation, depletion and amortization	(41,538,000)	(36,640,000)	(32,861,000)
Income tax expense	(27,796,000)	(15,536,000)	(12,411,000)
Results of operations for oil and gas producing activities	$ 50,998,000	26,128,000	22,673,000
Depreciation, depletion and amortization per equivalent barrel of production	$3.88	3.65	3.45

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

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

Quantities of Oil and Gas Reserves

Set forth below is a summary of the changes in the net quantities of crude oil, natural gas and natural gas liquids reserves for each of the three years ended December 31, 1996. Approximately 94%, 92% and 91%, of the respective year-end 1996, 1995 and 1994 domestic proved reserves were calculated by the independent petroleum consultants LaRoche Petroleum Consultants, Ltd. The remaining percentages of domestic reserves are based on Devon's own estimates. All of the 1996 Canadian proved reserves were calculated by the independent petroleum consultants AMH Group Ltd.

Total

	Oil (Bbls)	Gas (Mcf)	Natural Gas Liquids (Bbls)
Proved reserves as of December 31, 1993	14,897,000	369,254,000	1,854,000
Revisions of estimates	3,157,000	(5,540,000)	1,733,000
Extensions and discoveries	2,008,000	13,206,000	183,000
Purchase of reserves	25,201,000	13,492,000	2,181,000
Production	(2,467,000)	(39,335,000)	(501,000)
Sale of reserves	(631,000)	(3,517,000)	(8,000)
Proved reserves as of December 31, 1994	42,165,000	347,560,000	5,442,000
Revisions of estimates	1,127,000	(7,431,000)	535,000
Extensions and discoveries	2,959,000	9,645,000	472,000
Purchase of reserves	1,852,000	59,585,000	3,665,000
Production	(3,300,000)	(36,886,000)	(600,000)
Sale of reserves	(337,000)	(8,627,000)	(45,000)
Proved reserves as of December 31, 1995	44,466,000	363,846,000	9,469,000
Revisions of estimates	2,365,000	4,359,000	1,096,000
Extensions and discoveries	3,680,000	14,849,000	852,000
Purchase of reserves	21,189,000	249,922,000	2,130,000
Production	(3,816,000)	(35,714,000)	(952,000)
Sale of reserves	(403,000)	(1,743,000)	(16,000)
Proved reserves as of December 31, 1996	67,481,000	595,519,000	12,579,000
Proved developed reserves as of:			
December 31, 1993	11,548,000	355,536,000	1,751,000
December 31, 1994	18,718,000	324,302,000	3,123,000
December 31, 1995	28,703,000	311,664,000	6,149,000
December 31, 1996	60,202,000	570,265,000	11,212,000

Domestic

	Oil (Bbls)	Gas (Mcf)	Natural Gas Liquids (Bbls)
Proved reserves as of December 31, 1993	14,897,000	369,254,000	1,854,000
Revisions of estimates	3,157,000	(5,540,000)	1,733,000
Extensions and discoveries	2,008,000	13,206,000	183,000
Purchase of reserves	25,201,000	13,492,000	2,181,000
Production	(2,467,000)	(39,335,000)	(501,000)
Sale of reserves	(631,000)	(3,517,000)	(8,000)
Proved reserves as of December 31, 1994	42,165,000	347,560,000	5,442,000
Revisions of estimates	1,127,000	(7,431,000)	535,000
Extensions and discoveries	2,959,000	9,645,000	472,000
Purchase of reserves	1,852,000	59,585,000	3,665,000
Production	(3,300,000)	(36,886,000)	(600,000)
Sale of reserves	(337,000)	(8,627,000)	(45,000)
Proved reserves as of December 31, 1995	44,466,000	363,846,000	9,469,000
Revisions of estimates	2,365,000	4,359,000	1,096,000
Extensions and discoveries	3,680,000	14,849,000	852,000
Purchase of reserves	13,659,000	209,064,000	1,246,000
Production	(3,816,000)	(35,714,000)	(952,000)
Sale of reserves	(403,000)	(1,743,000)	(16,000)
Proved reserves as of December 31, 1996	59,951,000	554,661,000	11,695,000
Proved developed reserves as of:			
December 31, 1993	11,548,000	355,536,000	1,751,000
December 31, 1994	18,718,000	324,302,000	3,123,000
December 31, 1995	28,703,000	311,664,000	6,149,000
December 31, 1996	52,672,000	529,407,000	10,328,000

Canada

	Oil (Bbls)	Gas (Mcf)	Natural Gas Liquids (Bbls)
Proved reserves as of December 31, 1995	-	-	-
Revisions of estimates	-	-	-
Extensions and discoveries	-	-	-
Purchase of reserves	7,530,000	40,858,000	884,000
Production	-	-	-
Sale of reserves	-	-	-
Proved reserves as of December 31, 1996	7,530,000	40,858,000	884,000
Proved developed reserves as of December 31, 1996	7,530,000	40,858,000	884,000

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, 1996	1995	1994
Future cash inflows	$ 3,989,582,000	1,476,418,000	1,186,845,000
Future costs:			
Development	(54,133,000)	(52,327,000)	(75,115,000)
Production	(1,071,913,000)	(496,279,000)	(400,676,000)
Future income tax expense	(785,702,000)	(153,431,000)	(71,427,000)
Future net cash flows	2,077,834,000	774,381,000	639,627,000
10% discount to reflect timing of cash flows	(901,617,000)	(328,481,000)	(281,421,000)
Standardized measure of discounted future net cash flows	$ 1,176,217,000	445,900,000	358,206,000
Discounted future net cash flows before income taxes	$ 1,621,992,000	534,248,000	398,206,000

	Domestic December 31, 1996	1995	1994
Future cash inflows	$ 3,712,956,000	1,476,418,000	1,186,845,000
Future costs:			
Development	(54,064,000)	(52,327,000)	(75,115,000)
Production	(1,013,750,000)	(496,279,000)	(400,676,000)
Future income tax expense	(713,182,000)	(153,431,000)	(71,427,000)
Future net cash flows	1,931,960,000	774,381,000	639,627,000
10% discount to reflect timing of cash flows	(846,174,000)	(328,481,000)	(281,421,000)
Standardized measure of discounted future net cash flows	$ 1,085,786,000	445,900,000	358,206,000
Discounted future net cash flows before income taxes	$ 1,486,603,000	534,248,000	398,206,000

	Canada December 31, 1996	1995	1994
Future cash inflows	$276,626,000	-	-
Future costs:			
Development	(69,000)	-	-
Production	(58,163,000)	-	-
Future income tax expense	(72,520,000)	-	-
Future net cash flows	145,874,000	-	-
10% discount to reflect timing of cash flows	(55,443,000)	-	-
Standardized measure of discounted future net cash flows	$ 90,431,000	-	-
Discounted future net cash flows before income taxes	$135,389,000	-	-

Future cash inflows are computed by applying year-end prices (averaging $24.52 per barrel of oil, adjusted for transportation and other charges, $3.35 per Mcf of gas and $23.34 per barrel of natural gas liquids at December 31, 1996) 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. In addition to the future gas revenues calculated at $3.35 per Mcf, Devon's total future gas revenues also include the future tax credit payments to be received and recorded as gas revenues pursuant to the San Juan Basin Transaction described in Note 3. Devon's future total and domestic cash inflows shown in the tables above include $48.7 million related to these tax credit payments from 1997 through 2002. This amount has been calculated using the assumption that the year-end 1996 tax credit rate of $1.02 per MMBtu remains constant.

Future development and production costs are computed by estimating the expenditures to be incurred in developing and producing proved oil and gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions.

Future income tax expenses are computed by applying the appropriate statutory tax rates to the future pretax 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. Prior to the San Juan Basin Transaction as described in Note 3, the future income tax expenses estimated at December 31, 1994 were reduced by the estimated future Section 29 tax credits to be generated by the San Juan Basin coal seam gas properties. It was estimated at year-end 1994 that undiscounted amounts of approximately $113 million of Section 29 tax credits could be generated in future years to Devon's interest. However, because of limitations on the amount of Section 29 tax credits which can actually be utilized for income tax purposes, the undiscounted amounts included as reductions to future income tax expense for purposes of calculating the standardized measure of discounted future net cash flows were only $41 million at year-end 1994. As a result of the San Juan Basin Transaction, substantially all of the value of the Section 29 tax credits at year-end 1996 and 1995 is now included in "future cash inflows," instead of a reduction to income tax expense, in Devon's standardized measure of discounted future net cash flows.

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, 1996	1995	1994
Beginning balance	$445,900,000	358,206,000	343,550,000
Sales of oil, gas and natural gas liquids, net of production costs	(120,332,000)	(78,304,000)	(67,945,000)
Net changes in prices and production costs	519,456,000	60,498,000	(107,210,000)
Extensions, discoveries, and improved recovery, net of future development costs	42,522,000	22,308,000	14,629,000
Purchase of reserves, net of future development costs	576,234,000	50,000,000	133,103,000
Development costs incurred during the period which reduced future development costs	44,332,000	43,810,000	16,519,000
Revisions of quantity estimates	40,905,000	7,397,000	26,167,000
Sales of reserves in place	(6,499,000)	(7,933,000)	(5,281,000)
Accretion of discount	53,425,000	39,821,000	38,047,000
Net change in income taxes	(357,427,000)	(48,347,000)	(3,080,000)
Other, primarily changes in timing	(62,299,000)	(1,556,000)	(30,293,000)
Ending balance	$ 1,176,217,000	445,900,000	358,206,000

15. Supplemental Quarterly Financial Information (Unaudited)

Following is a summary of the unaudited interim results of operations for the years ended December 31, 1996 and 1995:

1996	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
Oil, gas and natural gas liquids sales	$33,734,229	36,743,221	39,007,410	53,073,462	162,558,322
Total revenues	$34,048,060	37,298,613	39,473,680	53,196,531	164,016,884
Net earnings	$ 5,553,926	6,775,388	7,707,673	14,763,545	34,800,532
Net earnings per share:					
Assuming no dilution	$0.25	0.31	0.35	0.66	1.57
Assuming full dilution	$0.25	0.31	0.35	0.59	1.52

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1995 - Actual Reported Results (a)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
Oil, gas and natural gas liquids sales	$23,519,568	25,331,966	33,589,019	29,985,087	112,425,640
Total revenues	$23,762,327	25,650,334	33,770,864	30,119,300	113,302,825
Net earnings	$ 1,026,802	2,444,422	6,645,531	4,385,144	14,501,899
Net earnings per share	$0.05	0.11	0.30	0.20	0.66

<F1>

1995 - Adjusted Results (a)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
Oil, gas and natural gas liquids					

sales	$26,478,770	28,293,715	27,668,068	29,985,087	112,425,640
Total revenues	$26,796,579	28,612,083	27,774,863	30,119,300	113,302,825
Net earnings	$ 2,864,127	4,181,531	3,071,097	4,385,144	14,501,899
Net earnings per share	$0.13	0.19	0.14	0.20	0.66

<F1>

(a) The San Juan Basin Transaction described in Note 3 was effective January 1, 1995. However, it was initially subject to a material contingency, and thus the transaction's impact on Devon's statement of operations was deferred pending the contingency's resolution. When the contingency was favorably resolved, the cumulative nine-month effect of the transaction was recorded in the third quarter. The second table above includes the 1995 quarterly results as reported, including the six-month out-of-period effect on the third quarter. The third table above presents the 1995 quarterly results as they would have been reported had the contingency not existed and had the San Juan Basin Transaction's effect on earnings been reported from the inception of the transaction on January 1, 1995.

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

Not applicable.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

The information called for by this Item 10 is incorporated herein by reference to the definitive Proxy Statement to be filed by the Company pursuant to Regulation 14A of the General Rules and Regulations under the Securities and Exchange Act of 1934 not later than April 30, 1997.

ITEM 11. EXECUTIVE COMPENSATION

The information called for by this Item 11 is incorporated herein by reference to the definitive Proxy Statement to be filed by the Company pursuant to Regulation 14A of the General Rules and Regulations under the Securities and Exchange Act of 1934 not later than April 30, 1997.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The information called for by this Item 12 is incorporated herein by reference to the definitive Proxy Statement to be filed by the Company pursuant to Regulation 14A of the General Rules and Regulations under the Securities and Exchange Act of 1934 not later than April 30, 1997.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

The information called for by this Item 13 is incorporated herein by reference to the definitive Proxy Statement to be filed by the Company pursuant to Regulation 14A of the General Rules and Regulations under the Securities and Exchange Act of 1934 not later than April 30, 1997.

PART IV

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

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

1. Consolidated Financial Statements

Reference is made to the Index to Consolidated Financial Statements and Consolidated Financial Statement Schedules appearing at Item 8 on Page 42 of this report.

2. Consolidated Financial Statement Schedules

All financial statement schedules are omitted as they are inapplicable, or the required information is immaterial.

3. Exhibits

2.1 Agreement and Plan of Merger and Reorganization by and among Registrant and Devon Energy Corporation, a Delaware corporation, dated as of April 13, 1995 (incorporated by reference to Exhibit A to Registrant's definitive Proxy Statement for its 1995 Annual Meeting of Shareholders filed on April 21, 1995).

2.2 Agreement and Plan of Merger among Registrant, Devon Energy Corporation (Nevada), Kerr-McGee Corporation, Kerr-McGee North American Onshore Corporation and Kerr- McGee Canada Onshore Ltd., dated October 17, 1996 (incorporated by reference to Addendum A to Registrant's definitive proxy statement for a special meeting of shareholders, filed on November 6, 1996).

3.1 Registrant's Certificate of Incorporation, as amended (incorporated by reference to Exhibit B to Registrant's definitive Proxy Statement for its 1995 Annual Meeting of Shareholders filed on April 21, 1995).

3.2 Registrant's Certificate of Amendment of Certificate of Incorporation (incorporated by reference to Exhibit 2 to Registrant's Current Report on Form 8-K dated December 31, 1996).

3.3 Registrant's Bylaws (incorporated by reference to Exhibit 3.2 to Registrant's Registration Statement on Form 8- B filed on June 7, 1995).

4.1 Form of Common Stock Certificate (incorporated by reference to Exhibit 4.1 to Registrant's Registration Statement on Form 8-B filed on June 7, 1995).

4.2 Rights Agreement between Registrant and The First National Bank of Boston (incorporated by reference to Exhibit 4.2 to Registrant's Registration Statement on Form 8-B filed on June 7, 1995).

4.3 First Amendment to Rights Agreement between Registrant and The First National Bank of Boston dated October 16, 1996 (incorporated by reference to Exhibit H- 1 to Addendum A to Registrant's definitive proxy statement for a special meeting of shareholders, filed on November 6, 1996).

4.4 Second Amendment to Rights Agreement between Registrant and the First National Bank of Boston, dated December 31, 1996 (incorporated by reference to Exhibit 4.2 to Registrant's Current Report on Form 8- K dated December 31, 1996).

4.5 Certificate of Designations of Series A Junior Participating Preferred Stock of Registrant (incorporated by reference to Exhibit 3.3 to Registrant's Registration Statement on Form 8-B filed on June 7, 1995).

4.6 Certificate of Trust of Devon Financing Trust [incorporated by reference to Exhibit 4.5 to Amendment No. 1 to Registrant's Registration Statement on Form S-
3 (No. 333-00815)].

4.7 Amended and Restated Declaration of Trust of Devon Financing Trust dated as of July 3, 1996, by J. Larry Nichols, H. Allen Turner, William T. Vaughn, The Bank of New York (Delaware) and The Bank of New York as Trustees and the Registrant as Sponsor [incorporated by reference to Exhibit 4.6 to Amendment No. 1 to Registrant's Registration Statement on Form S-3 (No. 333- 00815)].

4.8 Indenture dated as of July 3, 1996, between the Registrant and The Bank of New York [incorporated by reference to Exhibit 4.7 to Amendment No. 1 to Registrant's Registration Statement on Form S-
3 (No. 333-00815)].

4.9 First Supplemental Indenture dated as of July 3, 1996, between the Registrant and The Bank of New York [incorporated by reference to Exhibit 4.8 to Amendment No. 1 to Registrant's Registration Statement on Form S-3 (No. 333-00815)].

4.10 Form of 6 1/2% Preferred Convertible Securities (included as Exhibit A- 1 to Exhibit 4.5 above).

4.11 Form of 6 1/2% Convertible Junior Subordinated Debentures (included in Exhibit 4.7 above).

4.12 Preferred Securities Guarantee Agreement dated July 3, 1996, between Registrant, as Guarantor, and The Bank of New York, as Preferred Guarantee Trustee
[incorporated by reference to Exhibit 4.11 to Amendment No. 1 to Registrant's Registration Statement on Form S-3 (No. 333-00815)].

4.13 Stock Rights and Restrictions Agreement dated as of December 31, 1996, between Registrant and Kerr-McGee Corporation (incorporated by reference to Exhibit 4.3 to Registrant's Current Report on Form 8-K dated December 31, 1996).

4.14 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 Current Report on Form 8-K dated December 31, 1996).

10.1 Credit Agreement dated August 30, 1996, among Devon Energy Corporation (Nevada), as Borrower, the Registrant and Devon Energy Operating Corporation, as Guarantors, NationsBank of Texas, N.A., as Agent, and NationsBank of Texas, N.A., Bank One, Texas, N.A., Bank of Montreal, and First Union National Bank of North Carolina, as Lenders (incorporated by reference to Exhibit 10.1 to Registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 1996).

10.2 Devon Energy Corporation 1988 Stock Option Plan [incorporated by reference to Exhibit 10.4 to Registrant's Registration Statement on Form S-4 (No. 33-23564)].*

10.3 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).*

10.4 Severance Agreement between Devon Energy Corporation (Nevada), Devon Energy Corporation (Delaware) and Mr. J. Larry Nichols, dated December 3, 1992 (incorporated by reference to Exhibit 10.10 to Registrant's Amendment No. 1 to Annual Report on Form 10-K for the year ended December 31, 1992).*

10.5 Severance Agreement between Devon Energy Corporation (Nevada), Devon Energy Corporation (Delaware) and Mr. H. R. Sanders, Jr., dated December 3, 1992 (incorporated by reference to Exhibit 10.11 to Registrant's Amendment No. 1 to Annual Report on Form 10-K for the year ended December 31, 1992).*

10.6 Severance Agreement between Devon Energy Corporation (Nevada), Devon Energy Corporation (Delaware) and Mr. J. Michael Lacey, dated December 3, 1992 (incorporated by reference to Exhibit 10.12 to Registrant's Amendment No. 1 to Annual Report on Form 10-K for the year ended December 31, 1992).*

10.7 Severance Agreement between Devon Energy Corporation (Nevada), Devon Energy Corporation (Delaware) and Mr. H. Allen Turner, dated December 3, 1992 (incorporated by reference to Exhibit 10.13 to Registrant's Amendment No. 1 to Annual Report on Form 10-K for the year ended December 31, 1992).*

10.8 Severance Agreement between Devon Energy Corporation (Nevada), Devon Energy Corporation (Delaware) and Mr. Darryl G. Smette, dated December 3, 1992 (incorporated by reference to Exhibit 10.14 to Registrant's Amendment No. 1 to Annual Report on Form 10-K for the year ended December 31, 1992).*

10.9 Severance Agreement between Devon Energy Corporation (Nevada), Devon Energy Corporation (Delaware) and Mr. William T. Vaughn, dated December 3, 1992 (incorporated by reference to Exhibit 10.15 to Registrant's Amendment No. 1 to Annual Report on Form 10-K for the year ended December 31, 1992).*

10.10 Sale and Purchase Agreement relating to Registrant's San Juan Basin gas properties (incorporated by reference to Exhibit 10.15 to Registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 1995).

10.11 Second Restatement of and Amendment to Sale and Purchase Agreement relating to Registrant's San Juan Basin gas properties (incorporated by reference to Exhibit 10.16 to Registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 1995).

10.12 Purchase and Sale Agreement between Union Oil Company of California and Devon Energy Corporation (Nevada) (incorporated by reference to Exhibit 2 to Registrant's Current Report on Form 8-K dated December 18, 1995).

10.13 Registration Rights Agreement dated July 3, 1996, by and among the Registrant, Devon Financing Trust and Morgan Stanley & Co. Incorporated
[incorporated by reference to Exhibit 10.1 to Amendment No. 1 to Registrant's Registration Statement on Form S-3 (No. 333-00815)].

11 Computation of earnings per share

12 Computation of ratio of earnings to fixed charges

21 Subsidiaries of Registrant

23.1 Consent of LaRoche Petroleum Consultants, Ltd.

23.2 Consent of AMH Group Ltd.

23.3 Consent of KPMG Peat Marwick LLP

* Compensatory plans or arrangements.

(b) Reports on Form 8-K - No reports on Form 8-K were filed during the fourth quarter of 1996. A Current Report on Form 8-K dated January 14, 1997, was filed by the Registrant regarding the December 31, 1996, acquisition of the KMG-NAOS Properties.

FORM S-8 UNDERTAKING

For the purposes of complying with the amendments to the rules governing Form S-8 (effective July 13, 1990) under the Securities Act of 1933, the undersigned Registrant hereby undertakes as follows, which undertaking shall be incorporated by reference to the Registrant's Registration Statement on Form S-8 (No. 33-32378) and Registrant's Registration Statement on Form S-8 (No. 33-67924).

Insofar as indemnification for liabilities arising under the Securities Act of 1933 may be permitted to directors, officers and controlling persons of the Registrant pursuant to the foregoing provisions, or otherwise, the Registrant has been advised that in the opinion of the Securities and Exchange Commission such indemnification is against public policy as expressed in the Act and is, therefore, unenforceable. In the event that a claim for indemnification against such liabilities (other than the payment by the Registrant of expenses incurred or paid by a director, officer or controlling person of the Registrant in the successful defense of any action, suit or proceeding) is asserted by such director, officer or controlling person in connection with the securities being registered, the Registrant will, unless in the opinion of its counsel the matter has been settled by controlling precedent, submit to a court of appropriate jurisdiction the questions whether such indemnification by it is against public policy as expressed in the Act and will be governed by the final adjudication of such issue.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

DEVON ENERGY CORPORATION

March 6, 1997 By J. Larry Nichols J. Larry Nichols, President

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

March 6, 1997	By	John W. Nichols John W. Nichols Chairman of the Board and Director
March 6, 1997	By	J. Larry Nichols J. Larry Nichols President, Chief Executive Officer and Director
March 6, 1997	By	H. R. Sanders, Jr. H. R. Sanders, Jr. Executive Vice President and Director
March 6, 1997	By	William T. Vaughn William T. Vaughn Vice President - Finance
March 6, 1997	By	Danny J. Heatly Danny J. Heatly Controller

March 6, 1997	By	Luke R. Corbett Luke R. Corbett, Director
March 6, 1997	By	Thomas F. Ferguson Thomas F. Ferguson, Director

March 6, 1997 By David M. Gavrin David M. Gavrin, Director

March 6, 1997 By Michael E. Gellert Michael E. Gellert, Director

March 6, 1997 By Tom J. McDaniel Tom J. McDaniel, Director

March 6, 1997 By Lawrence H. Towell Lawrence H. Towell, Director

INDEX TO EXHIBITS

	Corporation (Delaware) and Mr. H. Allen Turner, dated December 3, 1992	#
10.8	Severance Agreement between Devon Energy Corporation (Nevada), Devon Energy Corporation (Delaware) and Mr. Darryl G. Smette, dated December 3, 1992	#
10.9	Severance Agreement between Devon Energy Corporation (Nevada), Devon Energy Corporation (Delaware) and Mr. William T. Vaughn, dated December 3, 1992	#
10.10	Sale and Purchase Agreement relating to Registrant's San Juan Basin gas properties	#
10.11	Second Restatement of and Amendment to Sale and Purchase Agreement relating to Registrant's San Juan Basin gas properties	#
10.12	Purchase and Sale Agreement between Union Oil Company of California and Devon Energy Corporation (Nevada)	#
10.13	Registration Rights Agreement dated July 3, 1996, by and among the Registrant, Devon Financing Trust and Morgan Stanley & Co. Incorporated	#
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EXHIBIT 11

DEVON ENERGY CORPORATION
Computation of Earnings Per Share

	Year Ended December 31,		
	1996	1995	1994
PRIMARY EARNINGS PER SHARE			
Computation for Statement of Operations			
Net earnings per statement of operations	$34,800,532	14,501,899	13,744,711
Weighted average common shares outstanding	22,159,507	22,073,550	21,551,581
Primary earnings per share	$1.57	0.66	0.64
Additional Primary Computation (A)			
Net earnings per statement of operations	$34,800,532	14,501,899	13,744,711
Adjustment to weighted average common shares outstanding:			
Weighted average as shown above in primary computation	22,159,507	22,073,550	21,551,581
Add dilutive effect of outstanding stock options (as determined using the treasury stock method)	191,298	127,640	117,799
Weighted average common shares outstanding, as adjusted	22,350,805	22,201,190	21,669,380
Net earnings per common share, as adjusted	$1.56	0.65	0.63
FULLY DILUTED EARNINGS PER SHARE (A)			
Net earnings per statement of operations	$34,800,532	14,501,899	13,744,711
Increase in net earnings from assumed conversion of Trust Convertible Preferred Securities (net of tax effect)	2,997,779	-	-
Net earnings, as adjusted	$37,798,311	14,501,899	13,744,711
Weighted average common shares outstanding as shown in primary computation above	22,159,507	22,073,550	21,551,581
Add fully dilutive effect of outstanding stock options (as determined using the treasury stock method)	317,610	181,446	118,211
Add weighted average of additional shares issued from assumed conversion of Trust Convertible Preferred Securities	2,383,793	-	-
Weighted average common shares outstanding, as adjusted	24,860,910	22,254,996	21,669,792
Fully diluted earnings per common share	$1.52	0.65	0.63

(A) The additional primary computations for all three years and the fully diluted computations for 1995 and 1994 are submitted in accordance with Regulation S-K item 601(b)(11) although not required by footnote 2 to paragraph 14 of APB Opinion No. 15 because they result in dilution of less than 3%.

EXHIBIT 12

DEVON ENERGY CORPORATION
Computation of Ratio of Earnings to Fixed Charges

	Year Ended December 31,		
	1996	1995	1994
Earnings before income taxes	$59,298,532	25,621,899	21,356,711
Add:			
Interest expense	5,276,527	7,051,142	5,438,911
Distributions on preferred securities of subsidiary trust	4,753,125	-	-
Amortization of costs incurred in connection with the offering of the preferred securities of subsidiary trust	82,003	-	-
Estimated interest factor of operating lease payments	190,726	182,129	173,923
Earnings, as adjusted (A)	$69,600,913	32,855,170	26,969,545
Fixed charges:			
Interest costs incurred	5,276,527	7,051,142	5,438,911
Distributions on preferred securities of subsidiary trust	4,753,125	-	-
Amortization of costs incurred in connection with the offering of the preferred securities of subsidiary trust	82,003	-	-
Estimated interest factor of operating lease payments	190,726	182,129	173,923
Total fixed charges (B)	$10,302,381	7,233,271	5,612,834
Ratio of earnings to fixed charges (A)/(B)	6.76	4.54	4.80

EXHIBIT 21

DEVON ENERGY CORPORATION

Subsidiaries of Registrant

The Registrant has the following significant subsidiaries:

Name of Subsidiary	Jurisdiction of Incorporation
Devon Energy Corporation (Nevada)	Nevada
Devon Energy Canada Corporation	Alberta, Canada
Devon Marketing Corporation	Nevada
Devon Production Corporation	Nevada
Devon Oil & Gas Company	Nevada
Catclaw Pipeline, Inc.	Oklahoma
DBC, Inc.	Oklahoma

EXHIBIT 23.1

ENGINEER'S CONSENT

We consent to incorporation by reference in the Registration Statements (No. 33-32378 and No. 33-67924) on Form S-8 and the Registration Statement (No. 333-00815) on Form S-3 of Devon Energy Corporation the reference to our appraisal report for Devon Energy Corporation as of December 31, 1996, which appears in the December 31, 1996 annual report on Form 10-K of Devon Energy Corporation.

LAROCHE PETROLEUM CONSULTANTS, LTD.
LAROCHE PETROLEUM CONSULTANTS, LTD.

March 6, 1997

EXHIBIT 23.2

ENGINEER'S CONSENT

We consent to incorporation by reference in the Registration Statements (No. 33-32378 and No. 33-67924) on Form S-8 and the Registration Statement (No. 333-00815) on Form S-3 of Devon Energy Corporation the reference to our appraisal report for Devon Energy Corporation as of December 31, 1996, which appears in the December 31, 1996 annual report on Form 10-K of Devon Energy Corporation.

AMH GROUP LTD.
AMH GROUP LTD.

March 6, 1997

EXHIBIT 23.3

INDEPENDENT AUDITORS' CONSENT

The Board of Directors and Stockholders
Devon Energy Corporation:

We consent to incorporation by reference in the Registration Statements (No. 33-32378 and 33-67924) on Form S-8 and the Registration Statement (No. 333-00815) on Form S-3 of Devon Energy Corporation of our report dated February 7, 1997, relating to the consolidated balance sheets of Devon Energy Corporation and subsidiaries as of December 31, 1996, 1995 and 1994 and the related consolidated statements of operations, stockholders' equity, and cash flows for each of the years then ended, which report appears in the December 31, 1996 annual report on Form 10- K of Devon Energy Corporation.

KPMG Peat Marwick LLP KPMG Peat Marwick LLP

Oklahoma City, Oklahoma
March 5, 1997

ARTICLE 5

PERIOD TYPE	12 MOS
FISCAL YEAR END	DEC 31 1996
PERIOD END	DEC 31 1996
CASH	9401350
SECURITIES	0
RECEIVABLES	29580306
ALLOWANCES	0
INVENTORY	2103486
CURRENT ASSETS	43373894
PP&E	974805756
DEPRECIATION	281959410
TOTAL ASSETS	746250800
CURRENT LIABILITIES	23640255
BONDS	8000000
PREFERRED MANDATORY	3214130
PREFERRED	0
COMMON	0
OTHER SE	469190287
TOTAL LIABILITY AND EQUITY	746250800
SALES	162558322
TOTAL REVENUES	164016884
CGS	0
TOTAL COSTS	0
OTHER EXPENSES	42226242
LOSS PROVISION	0
INTEREST EXPENSE	5276527
INCOME PRETAX	59298532
INCOME TAX	24498000
INCOME CONTINUING	34800532
DISCONTINUED	0
EXTRAORDINARY	0
CHANGES	0
NET INCOME	34800532
EPS PRIMARY	1.57
EPS DILUTED	1.52

End of Filing