DEVON ENERGY CORP /OK/

FORM 10-K405
(Annual Report (Regulation S-K, item 405))

Filed 03/13/98 for the Period Ending 12/31/97

Address	20 N BROADWAY STE 1500 OKLAHOMA CITY, OK 73102-8260
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SIC Code	1311 - Crude Petroleum and Natural Gas
Fiscal Year	12/31

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Address	20 N BROADWAY STE 1500
	OKLAHOMA CITY, Oklahoma 73102-8260
Telephone	405-235-3611
CIK	0000837330
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, 1997 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	73-1474008
(State or Other Jurisdiction of Incorporation or Organization)	(I.R.S. Employer Identification No.)
20 North Broadway, Suite 1500 Oklahoma City, Oklahoma	73102-8260
(Address of Principal Executive Offices)	(Zip Code)

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

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

Title of each class	Name of each exchange on which registered
Common Stock, par value $.10 per share	American Stock Exchange

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, 1998, was $719,015,211. At such date 32,318,895 shares of common stock were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Proxy statement for the 1998 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 "MMBtu" means million British thermal units, a measure of heating value "Bbl" means barrel "MBbls" means thousand barrels "MMBbls" means million barrels "Boe" means equivalent barrels of oil "MBoe" means thousand equivalent barrels of oil "MMBoe" means million equivalent barrels of oil "Oil" includes crude oil and condensate "NGLs" means natural gas liquids

DISCLOSURE REGARDING FORWARD-LOOKING STATEMENTS

THIS REPORT INCLUDES "FORWARD-LOOKING STATEMENTS" WITHIN THE MEANING OF SECTION 27A OF THE SECURITIES ACT OF 1933, AS AMENDED, AND SECTION 21E OF THE SECURITIES EXCHANGE ACT OF 1934, AS AMENDED. ALL STATEMENTS OTHER THAN STATEMENTS OF HISTORICAL FACTS INCLUDED IN THIS REPORT, INCLUDING, WITHOUT LIMITATION, STATEMENTS REGARDING THE COMPANY'S FUTURE FINANCIAL POSITION, BUSINESS STRATEGY, BUDGETS, PROJECTED COSTS AND PLANS AND OBJECTIVES OF MANAGMENT FOR FUTURE OPERATIONS, ARE FORWARD-LOOKING STATEMENTS. IN ADDITION, FORWARD-LOOKING STATEMENTS GENERALLY CAN BE IDENTIFIED BY THE USE OF FORWARD-LOOKING TERMINOLOGY SUCH AS "MAY", "WILL", "EXPECT", "INTEND", "ESTIMATE", "ANTICIPATE", "BELIEVE", OR "CONTINUE" OR THE NEGATIVE THEREOF OR VARIATIONS THEREON OR SIMILAR TERMINOLOGY. ALTHOUGH THE COMPANY BELIEVES THAT THE EXPECTATIONS REFLECTED IN SUCH FORWARD-LOOKING STATEMENTS ARE REASONABLE, IT CAN GIVE NO ASSURANCE THAT SUCH EXPECTATIONS WILL PROVE TO HAVE BEEN CORRECT. IMPORTANT FACTORS THAT COULD CAUSE ACTUAL RESULTS TO DIFFER MATERIALLY FROM THE COMPANY'S EXPECTATIONS ("CAUTIONARY STATEMENTS") ARE DISCLOSED UNDER "ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS 1998 ESTIMATES", ITEM 2. "PROPERTIES - PROVED RESERVES AND ESTIMATED FUTURE NET REVENUES" AND ELSEWHERE IN THIS REPORT. ALL SUBSEQUENT WRITTEN AND ORAL FORWARD-LOOKING STATEMENTS ATTRIBUTABLE TO THE COMPANY, OR PERSONS ACTING ON ITS BEHALF, ARE EXPRESSLY QUALIFIED IN THEIR ENTIRETY BY THE CAUTIONARY STATEMENTS. THE COMPANY ASSUMES NO DUTY TO UPDATE OR REVISE ITS FORWARD-LOOKING STATEMENTS BASED ON CHANGES IN INTERNAL ESTIMATES OR EXPECTATIONS OR OTHERWISE.

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 as a privately-held company. 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 405/2353611).

Devon currently owns interests in approximately 1,700 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 17 hereof.)

At December 31, 1997, Devon's estimated proved reserves were 184.0 MMBoe, which were relatively balanced between oil and NGLs (44%) and natural gas (56%). The present value of pre-tax future net revenues discounted at 10% per annum assuming essentially unescalated prices ("10% Present Value") of such reserves was $913 million. 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 5 significant acquisitions and drilled 873 new wells, 842 of which were producers. These activities have resulted in net reserve additions (i.e., extensions, discoveries, purchases and revisions) of 189.5 MMBoe. Capital costs incurred to complete these activities totaled $736.8 million, for a five-year finding and development cost of $3.89 per Boe. Net reserve additions divided by production, resulted in an annual average reserve replacement factor of 320%.

Devon's objective, however, is to increase value per share, not simply to increase total assets. Reserves have grown from 2.94 Boe per diluted share at year-end 1992 to 4.91 Boe per diluted share at year-end 1997. During this same five-year period, net debt (long-term debt minus working capital) has remained relatively low, never exceeding $1.17 per Boe. In fact, at year-end 1997, the Company had no debt and had working capital of $0.34 per Boe.

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

On February 13, 1998, the Company commenced a tender offer (the "Offer") for any and all of the units of beneficial interest ("Units") of Burlington Resources Coal Seam Gas Royalty Trust (the "Trust"). The Offer of $8.75 per Unit in cash is not conditioned on the tender of any minimum or maximum number of Units. The initial expiration of the Offer is expected to be March 13, 1998.

If all of the Trust's Units are tendered, the transaction would have a total value of approximately $80 million. Devon anticipates using its cash on hand and committed credit lines to fund the transaction.

As of February 24, 1998, results of the Offer were not known, and no estimate could be made as to how many Units of the Trust will be acquired, if any. Devon intends to hold any Units it acquires in the Offer for investment purposes. The Trust holds certain economic interests in the Northeast Blanco Unit ("NEBU") of northwest New Mexico. Devon is the operator of and owns a significant reserve position in this property. See "Item 2 Properties. Significant Properties - San Juan Basin Northeast Blanco Unit."

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 1998 will be concentrated in the Permian Basin, the Rocky Mountains, the Texas Panhandle 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
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
1997(3)	268	9	277	119.20	4.90	124.10
	809	20	829	487.91	7.82	495.73

Exploratory Wells

	Gross (1)			Net (2)		
	Productive	Dry	Total	Productive	Dry	Total
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
1997(3)	16	2	18	6.10	1.50	7.60
	33	11	44	12.70	5.62	18.32

(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.
(3) Included in the 1997 figures are 24 gross (10.2 net) productive development wells and 2 gross (1.1 net) productive exploratory wells drilled in Canada. Devon drilled no dry holes in Canada. Devon had no Canadian properties prior to December 31, 1996.

As of December 31, 1997, Devon was participating in the drilling of 54 gross (17.6 net) wells, which are not included in the table above. All such wells were being drilled in the United States. Through February 24, 1998, 15 gross (10.1 net) wells had been completed as productive. The remaining were still in process.

Customers

For the years ended December 31, 1997 and December 31, 1996, one significant purchaser, Aquila Energy Marketing Corporation ("Aquila"), accounted for 46% and 45%, respectively, of Devon's natural gas sales or 22% and 19%, respectively, of total revenue. 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 or 14% and 7%, respectively, of total revenue. 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. A large portion of Devon's natural gas production is sold at variable or market-sensitive prices. Though exact percentages vary daily, as of December 31, 1997, approximately 73% of such natural gas is sold under short-term contracts. The remaining 27% 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 may 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 one year 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.

Physical Delivery Contracts. As of February 24, 1998, Devon had made firm commitments to sell an average of approximately 30% of its estimated 1998 coal seam gas production (or approximately 9% of total estimated 1998 gas production) at a fixed price of approximately $1.45 per Mcf, which equates to a price of approximately $2.04 per MMBtu. (The $1.45 per Mcf price includes the effect of adjusting for Btu content and is net of costs for transportation and removing carbon dioxide. This price excludes the expected benefit of the San Juan Basin Transaction. See "Item 2. Properties - Significant Properties - San Juan Basin San Juan Basin Transaction"). Devon has also made other firm commitments to sell certain quantities of its 1998 domestic conventional and Canadian gas production at fixed prices. However, such other commitments are not material.

If Devon is unable to produce the volumes required to fulfill its firm commitments, Devon would have to purchase gas on the open market to satisfy such commitments. During the past five years, Devon has satisfied all of its firm commitments from its production and anticipates that it will continue to do so in the future.

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 utilize natural gas storage facilities and purchase some of their anticipated winter requirements during the summer. This can also lessen seasonal demand fluctuations.

Government Regulation

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

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 is committed to meeting its responsibilities to protect the environment wherever it operates and anticipates making increased expenditures of both a capital and expense nature as a result of the increasingly stringent laws relating to the protection of the environment. Devon's unreimbursed expenditures in 1997 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.

Canadian Regulation

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

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

Royalties and Incentives. Each province of Canada has legislation and regulations governing land tenure, royalties, production rates and taxes, 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 parties. Crown royalties are determined by government regulation and are generally calculated as a percentage of the value of the gross production with the royalty rate dependent in part upon prescribed reference prices, well productivity, geographical location, field discovery date and the type of quality of the petroleum product produced. From time to time, the governments of Canada, Alberta and British Columbia have also established incentive programs such as royalty rate reductions, royalty holidays and tax credits for the purpose of encouraging oil and natural gas exploration or enhanced recovery projects. These incentives generally have the effect of increasing the cash flow to the producer.

Pricing and Marketing. The price of oil and natural gas sold is determined by negotiation between buyers and sellers. An order from the National Energy Board ("NEB") is required for oil exports. Any oil export to be made pursuant to an export contract of longer than one year, in the case of light crude, and two years, in the case of heavy crude, duration (up to 25 years) requires an exporter to obtain an export license form the NEB. The issue of such a license requires the approval of the Governor in Council. Natural gas exported from Canada is also subject to similar regulation by the NEB and the government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts in excess of two years must continue to meet certain criteria prescribed by the NEB and the government of Canada. The governments of Alberta and British Columbia also regulate the volume of natural gas which may be removed from those provinces for consumption elsewhere based on such factors as reserve availability, transportation arrangements and market considerations.

Environmental Regulation. The oil and natural gas industry is subject to environmental regulation pursuant to local, provincial and federal legislation. Environmental legislation provides for restrictions and prohibitions on releases or emissions of various substances produced or utilized in association with certain oil and gas industry operations. In addition, legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. A breach of such legislation may result in the imposition of fines and penalties. Devon is committed to meeting its responsibilities to protect the environment wherever it operates and anticipates making increased expenditures of both a capital and expense nature as a result of the increasingly stringent laws relating to the protection of the environment. Devon's unreimbursed expenditures in 1997 concerning such matters were immaterial, but Devon cannot predict with any reasonable degree of certainty its future exposure concerning such matters.

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

Employees

As of December 31, 1997, Devon's staff consisted of 383 fulltime employees, including 32 professionals in engineering, 16 in geology, 21 in the land department, 9 in oil and gas marketing, 53 in accounting and data processing, 21 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.

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, 1997. Approximately 92% 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 its estimates, 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). LaRoche and AMH indicated in their reports that they also used standard geological and engineering methods generally accepted by the petroleum industry and in accordance with SEC guidelines. 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. Please refer to the supplemental information on oil and gas operations in note 14 to Devon's consolidated financial statements (included herein) for a presentation of reserves separated between Canada and the U.S.

	Total Proved Reserves	Proved Developed Reserves (1)	Proved Undeveloped Reserves (2)
Oil (MBbls)	68,443	60,165	8,278
Gas (MMcf)	616,004	506,374	109,630
NGLs (MBbl)	12,881	12,098	783
MBoe (3)	183,991	156,658	27,333
Pre-tax Future Net Revenue ($ thousands) (4)	1,562,022	1,390,359	171,663
Pre-tax 10% Present Value ($ thousands) (4)	913,073	841,036	72,037

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

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

(3) Gas reserves are converted to 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 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, 1997. These prices were not changed except where different prices were fixed and determinable from applicable contracts. These assumptions yield average prices over the life of Devon's properties of $16.93 per Bbl of oil, $1.89 per Mcf of natural gas ($1.94 per Mcf including the effect of the San Juan Basin Transaction), and $12.42 per Bbl of NGLs. These prices compare to December 31, 1997, benchmark posted prices of $15.50 per Bbl for West Texas Intermediate crude oil and a composite of $2.34 per MMBtu for Texas Gulf Coast spot gas, representing prices paid for gas delivered to various Texas Gulf Coast pipelines.

No estimates of Devon's proved reserves have been filed with or included in reports to any federal or foreign governmental authority or agency since the beginning of the last fiscal year except (i) in filings with the SEC and (ii) in filings with the Department of Energy ("DOE"). Reserve estimates filed by Devon with the SEC correspond with the estimates of Devon reserves contained herein. Reserve estimates filed with the DOE are based upon the same underlying technical and economic assumptions as the estimates of Devon's reserves included herein. However, the DOE requires reports to include the interests of all owners in wells 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, 1997. 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 95%, 91%, 92%, 94% and 92% of Devon's domestic reserves as of the years ended December 31, 1993, 1994, 1995, 1996 and 1997, respectively, were estimated by LaRoche. The balance of the domestic reserves was estimated by Devon's internal staff of engineers. All of the Canadian reserves as of the years ended December 31, 1996 and 1997, were estimated by AMH. (Devon had no Canadian reserves prior to 1996.)

Total Proved Reserves

As of December 31,	Oil (MBbls)	Gas (MMcf)	NGLs(MBbls)	Total (Mboe)
1993	14,897	369,254	1,854	78,293
1994	42,165	347,560	5,442	105,534
1995	44,466	363,846	9,469	114,576
1996	67,481	595,519	12,579	179,313
1997	68,443	616,004	12,881	183,991

Proved Developed Reserves

As of December 31,	Oil (MBbls)	Gas (MMcf)	NGLs(MBbls)	Total (MBoe)
1993	11,548	355,536	1,751	72,555
1994	18,718	324,302	3,123	75,891
1995	28,703	311,664	6,149	86,796
1996	60,202	570,265	11,212	166,458
1997	60,165	506,374	12,098	156,659

Production, Revenue and Price History

Certain information concerning oil and natural gas production, prices, revenues (net of all royalties, overriding royalties and other third party interests) and operating expenses for the three years ended December 31, 1997, is set forth in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations."

Well Statistics

As of December 31, 1997, Devon held interests in approximately 1700 properties. The following table depicts Devon's interests in producing wells located on these properties:

	Oil Wells		Gas Wells		Total Wells	
	Gross(1)	Net(2)	Gross(1)	Net(2)	Gross(1)	Net(2)
U. S.	8,427	1,230	2,852	703	11,279	1,933
Canada	692	117	234	61	926	178
Total	9,119	1,347	3,086	764	12,205	2,111

(1) Gross wells are the total number of wells in which Devon owns a working interest.
(2) Net refers to gross wells multiplied by Devon's fractional working interests therein.

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

Undeveloped Acreage

The following table sets forth Devon's developed and undeveloped oil and gas lease and mineral acreage as of December 31, 1997.

	Developed		Undeveloped	
	Gross(1)	Net(2)	Gross(1)	Net(2)
Alabama	4,662	2,247	583	261
Arkansas	5,906	589	14,649	3,627
Colorado	6,348	2,581	22,319	9,519
Kansas	20,036	8,693	6,433	713
Louisiana	12,840	5,047	12,680	5,769
Mississippi	8,291	548	4,148	1,206
Montana	16,326	365	11,891	1,779
Nebraska	160	80	6,517	1,377
New Mexico	145,481	61,199	237,695	79,953
North Dakota	9,427	3,506	11,453	2,355
Oklahoma	278,720	85,017	212,230	48,160
South Dakota	6,051	149	162	78
Texas	858,224	228,070	608,034	184,955
Utah	5,305	864	2,200	2,200
Wyoming	195,067	82,078	135,265	76,361
Total U. S.	1,572,844	481,033	1,286,259	418,313
Canada	187,621	76,200	113,663	75,732
Grand Total	1,760,465	557,233	1,399,922	494,045

(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 2,133 of its 12,205 wells. These operated wells account for approximately 57% of Devon's total proved reserves. 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 proved reserve information on the most significant geographic areas in which Devon's properties are located as of December 31, 1997.

	Oil(MBbls)	Gas(MMcf)	NGLs(MBbl)	MBoe(1)	MBoe% (2)	10% Presents Value (3) ($000)	10% Present Value% (4)

Permian Basin:							
West Texas and							
Southeast New Mexico							
Grayburg-Jackson							
Field	19,296	1,539	1,539	21,864	11.9%	$101,060	11.1%
Ozona Field	247	50,476	2,553	11,213	6.1%	51,531	5.6%
Other	22,061	74,068	3,199	37,605	20.4%	191,797	21.0%
Total	41,604	130,718	7,291	70,682	38.4%	$344,388	37.7%
San Juan Basin:							
Northwest New Mexico							
Northeast Blanco							
Unit	4	148,699	40	24,827	13.5%	$120,881 (5)	13.2%
32-9 Unit	0	80,502	0	13,417	7.3%	60,717 (6)	6.7%
Other	3	280	10	60	0.0%	162	0.0%
Total	7	229,481	50	38,304	20.8%	$181,760	19.9%
Rocky Mountains:							
Colorado and Wyoming							
House Creek	11,656	675	0	11,768	6.4%	$43,266	4.7%
Other	5,217	86,570	2,953	22,598	12.3%	106,470	11.7%
Total	16,873	87,245	2,953	34,366	18.7%	$149,736	16.4%
Mid-Continent:							
Oklahoma and							
Texas Panhandle	2,119	112,815	1,778	22,699	12.3%	$134,360	14.7%
Canada	7,541	48,180	809	16,380	8.9%	$92,625 (7)	10.2%
All Other Properties	299	7,565	0	1,560	0.9%	$10,204	1.1%
Grand Total	68,443	616,004	12,881	183,991	100.0%	$913,073	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 $17.6 million of additional value attributable to the San Juan Basin Transaction through the year 2002.
(6) Includes $11.1 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: $0.6992 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 producing 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 wellsituated 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 onethird 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 acres per well spacing and subsequent waterflooding. Based upon analogy to these properties, Devon initiated a $75 million capital development project in 1994. The project included drilling approximately 185 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 1996. The majority of the field was in the initial phases of water injection by mid-1997. Completion of the waterflood facilities over the remainder of the field will require the additional conversion of about 30 producing wells to injection wells.

At year-end 1997, 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 primarily from the Canyon and Strawn Formations at depths ranging from approximately 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.

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 been historically 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 could 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 97%, or 144.5 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.

In the near term, Devon is implementing various projects which have already increased and may continue to increase production and recoverable reserves. The first of these projects, called "line looping," involves laying additional gathering lines to decrease operating pressures. This project was begun in 1996 and was substantially completed in October, 1997. Another project involves the installation of additional compressors at various points in the gathering system and at central delivery points associated with NEBU. This project was begun in 1997 and will continue in 1998. Additional projects to improve production through work on individual wells are currently underway. Longer term, Devon believes that additional wells may be drilled which could improve production.

Initial results from the portion of the line looping and compression projects that have been completed through February 24, 1998, appear favorable. Total daily production from NEBU has increased from an average of 187 MMcf of gas per day in June 1996 to an average of 209 MMcf of gas per day in January 1998. Devon anticipates that the installation of additional compression and facilities could increase production from NEBU another 10 MMcf to 20 MMcf of gas per day. As part of the San Juan Basin Transaction (discussed in more detail below), a third party will pay 100% of Devon's share 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.

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. 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. Longer term, Devon believes that additional wells may be drilled which could improve production. 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 range between $0.40 and $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.

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.

House Creek Field. The House Creek Field is located in Campbell County, Wyoming within the prolific Powder River Basin. Devon acquired its original interest in the field at year-end 1996. In 1997, the Company purchased additional interests. The field, which produces oil from the Sussex Sandstone reservoir at depths of 8,200 feet, covers an area thirty miles long and two miles wide. The Field is divided into two production units. The southern two-thirds of the field, designated as the House Creek Sussex Unit, is operated by Devon with a 45.4% working interest. A 12 well infill drilling program was initiated late in 1997. Based on the success of that program, an additional 60 to 80 wells could be drilled in 1998, effectively reducing well spacing from 160 to 80 acres per well. The northern third of the field, designated as the House Creek North Sussex Unit, is operated by a third party. Devon has a 26.5% working interest in the North Unit. Additional infill drilling is also underway in the North Unit. Both portions of the field are currently under waterflood.

Title to Properties

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

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

ITEM 3. LEGAL PROCEEDINGS

Devon is involved in various routine legal proceedings incidental to its business. However, to Devon's knowledge as of February 24, 1998, there were no material pending legal proceedings to which Devon is a party or to which any of its property is subject.

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

No matters were submitted to a vote of the Company's security holders during the fourth quarter of the year ended December 31, 1997.

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	Consolidated Average Daily Volume
1996:			
Quarter Ended March 31, 1996	25-3/4	19-7/8	44,846
Quarter Ended June 39, 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	38-7/8	29-1/2	73,079
Quarter Ended June 30, 1997	38-1/2	27-3/8	87,800
Quarter Ended September 30, 1997	45-1/4	36-1/8	6,174
Quarter Ended December 31, 1997	49-1/8	35	69,694
1998:			
Quarter Ended March 31, 1998 (through February 24, 1998)	38-3/8	33	93,914

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 $0.14 per share. Total dividends for 1997 were $0.20 per share. Devon anticipates continuing to pay regular quarterly dividends in the foreseeable future.

On February 24, 1998, there were 859 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,				
	1997	1996	1995	1994	1993
	(Thousands, Except Per Share Data and Ratios)				
OPERATING RESULTS					
Oil sales	$ 133,445	80,142	55,290	38,086	38,395
Gas sales	150,549	68,049	50,732	56,372	54,876
NGL sales	21,754	14,367	6,404	4,908	4,544
Other revenue	7,392	1,459	877	1,407	942
Total revenues	$ 313,140	164,017	113,303	100,773	98,757
Lease operating expenses	$ 65,655	31,568	27,289	24,521	26,401
Production taxes	$ 17,924	10,658	6,832	6,899	6,924
Depreciation, depletion and amortization	$ 85,307	43,361	38,090	34,132	28,409
General and administrative expenses	$ 12,922	9,101	8,419	8,425	7,640
Interest expense	$ 274	5,277	7,051	5,439	3,422
Distributions on preferred securities of subsidiary trust	$ 9,717	4,753	--	--	--
<F1>					
Net earnings	$ 75,292	34,801	14,502	13,745	20,4861
Net earnings per share:					
<F1>					
Basic	$ 2.34	1.57	0.66	0.64	0.98 1
<F1>					
Diluted	$ 2.17	1.52	0.65	0.63	0.98 1
Cash dividends per common share	$ 0.20	0.14	0.12	0.12	0.09
Weighted average common shares outstanding - basic	32,216	22,160	22,074	21,552	20,822
Ratio of earnings to fixed					
<F2>					
charges 2	12.52	6.76	4.54	4.80	8.24

	December 31,				
	1997	1996	1995	1994	1993
	(Thousands)				
BALANCE SHEET DATA					
Total assets	$ 846,403	746,251	421,564	351,448	285,553
Long-term debt	$ -	8,000	143,000	98,000	80,000
Convertible preferred securities of subsidiary trust	$ 149,500	149,500	--	--	--
Stockholders' equity	$ 543,576	472,404	219,041	206,406	172,900

	Year Ended December 31,				
	1997	1996	1995	1994	1993
	(Thousands, Except Per Unit Data)				
CASH FLOW DATA					
Net cash provided by operating activities	$ 168,722	86,802	61,276	46,384	63,957
<F4>					
<F3>					
EBITDA 3,4	216,639	112,689	70,763	60,928	57,792
<F4>					
<F5>					
Cash margin 4,5	181,445	95,951	59,217	55,074	52,893
PRODUCTION, PRICE AND OTHER DATA					
Production:					
Oil (MBbls)	7,005	3,816	3,300	2,467	2,337
Gas (MMcf)	69,327	35,714	36,886	39,335	35,598
NGLs (MBbls)	1,626	952	600	501	411
<F6>					
MBoe 6	20,185	10,720	10,047	9,524	8,681

Average prices:					
Oil (Per Bbl)	$19.05	21.00	16.75	15.44	16.43
Gas (Per Mcf)	$ 2.17	1.91	1.38	1.43	1.54
NGLs (Per Bbl)	$13.38	15.09	10.68	9.79	11.06
<F6>					
Per Boe [6]	$15.15	15.16	11.19	10.43	11.27
Costs per Boe:					
Operating costs	$ 4.14	3.94	3.40	3.30	3.84
Depreciation, depletion and amortization of oil and gas properties	$ 4.08	3.88	3.65	3.45	3.16
General and administrative expenses	$ 0.64	0.85	0.84	0.89	0.88

<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 EBITDA represents earnings before interest (including distributions on preferred securities of subsidiary trust), taxes, depreciation, depletion and amortization.

<F4>
4 EBITDA and cash margin (defined below) 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, 1997, 1996, 1995, 1994, and 1993, net cash used in investing activities were $131.3 million, $94.8 million, $110.6 million, $73.4 million and $74.2 million, respectively. For these same periods, net cash provided (used) by financing activities were ($4.5) million, $8.5 million, $49.8 million, $15.8 million and $24.2 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 1995 through 1997. Reference is made to "Item 6. Selected Financial Data" and "Item 8. Financial Statements and Supplementary Data."

Overview

Devon concluded 1997 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 74% to 184 million barrels of oil equivalent ("MMBoe"). The company s unused long-term credit lines have increased 64% over the same period, to $208 million. Total assets have increased 141% to $846 million. During the same three years Devon reduced its long-term debt from $98 million to zero and significantly increased stockholders equity.

Devon s operating performance has also improved by most measures over the last three years. The 1997 oil and gas production of 20.2 MMBoe was 112% over that of 1994. The 1997 production increase, coupled with a 45% increase in oil, gas and NGL prices over 1994 levels, led to revenues and earnings gains. Net earnings for 1997 climbed 448% over those of 1994, to $75.3 million. Net cash provided by operating activities rose from $46.4 million in 1994 to $168.7 million in 1997. <F1> The cash margin1 (total revenues less cash expenses) during these same three years has increased from $55.1 million in 1994 to $181.4 million in 1997.

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

Devon acquired Alta Energy Corporation through a $72 million cash and common stock merger in May 1994. The merger added substantial oil and gas reserves, production and revenues to Devon's Permian Basin position.

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 $8 million, $10

<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.

million and $12 million to Devon's annual revenues in 1997, 1996 and 1995, respectively. See Note 3 to the consolidated financial statements included elsewhere in this report for a detailed discussion of the San Juan Basin Transaction.

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. During such period, Devon has spent approximately $246 million to drill 688 wells, of which 667 were completed as producers.

Prices received from oil, gas and NGL revenues have risen (though with volatility) 45%, from $10.43 per Boe in 1994 to $15.15 per Boe in 1997.

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

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 120.4 MMBoe of proved reserves to its asset base. Combined with 1.8 MMBoe of upward revisions to its reserve estimates, Devon's total reserve additions of 122.2 MMBoe during the past three years were 298% of its production of 41.0 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"). Combined with cash flow from operations, this transaction has eliminated Devon's long-term debt.

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 unused lines of credit. Since the end of 1994, Devon's available long-term credit lines have increased by $81 million to a total of

$208 million at year-end 1997.

The growth exhibited by Devon over the last three years extends a nine-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 nine-year period, volatility in oil and gas prices has resulted in considerable variability in earnings and cash flows. Prices for oil, natural gas and NGLs are determined primarily by market conditions. Market conditions for these products have been, and will continue to be, influenced by regional and world-wide economic growth, weather and other factors that are beyond Devon s control. Devon s future earnings and cash flows will continue to depend on market conditions.

Like all oil and gas production companies, Devon faces the challenge of natural production decline. As virgin pressures are depleted, oil and gas production from a given well naturally decrease. Thus, an oil and gas production company depletes 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.

Given the dependence of oil and gas prices on factors outside of Devon's control, the company s management has focused its efforts on increasing oil and gas reserves and production and on controlling expenses. Over its nine 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 three years Devon s per-unit operating costs have increased by 25%. 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. (Secondary recovery projects are generally more expensive than primary production. In addition, producing oil is generally more expensive than producing gas. However, oil also generally produces more revenue per Boe than gas.) Higher oil, gas and NGL revenues in 1997 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 reserves.

Results of Operations

Devon's total revenues have risen from $113.3 million in 1995 to $164.0 million in 1996 and $313.1 million in 1997. In each of these years, oil, gas and NGL sales accounted for over 97% of total revenues.

Changes in oil, gas and NGL production, prices and revenues from 1995 to 1997 are shown in the table below. (Note: Unless otherwise stated, all references in this discussion to dollar amounts regarding Devon's Canadian operations are expressed in U.S. dollars.)

	Total Year Ended December 31, (Absolute Amounts in Thousands)				
	1997	1997 vs 1996	1996	1996 vs 1995	1995
Production					
Oil (MBbls)	7,005	+84%	3,816	+16%	3,300
Gas (MMcf)	69,327	+94%	35,714	-3%	36,886
NGLs (MBbls)	1,626	+71%	952	+59%	600
Oil, Gas and NGLs (MBoe)	20,185	+88%	10,720	+7%	10,047
Revenues					
Per Unit of Production:					
Oil (per Bbl)	$ 19.05	-9%	21.00	+25%	16.75
Gas (per Mcf)	$ 2.17	+14%	1.91	+38%	1.38
NGLs (per Bbl)	$ 13.38	-11%	15.09	+41%	10.68
Oil, Gas and NGLs (per Boe)	$ 15.15	-	15.16	+35%	11.19
Absolute:					
Oil	$133,445	+67%	80,142	+45%	55,290
Gas	$150,549	+121%	68,049	+34%	50,732
NGLs	$ 21,754	+51%	14,367	+124%	6,404
Oil, Gas and NGLs	$305,748	+88%	162,558	+45%	112,426

	Domestic Year Ended December 31, (Absolute Amounts in Thousands)				
	1997	1997 vs 1996	1996	1996 vs 1995	1995
Production					
Oil (MBbls)	6,055	+59%	3,816	+16%	3,300
Gas (MMcf)	61,015	+71%	35,714	-3%	36,886
NGLs (MBbls)	1,468	+54%	952	+59%	600
Oil, Gas and NGLs (MBoe)	17,692	+65%	10,720	+7%	10,047

Revenues					
Per Unit of Production:					
Oil (per Bbl)	$ 19.08	-9%	21.00	+25%	16.75
Gas (per Mcf)	$ 2.28	+19%	1.91	+38%	1.38
NGLs (per Bbl)	$ 13.18	-13%	15.09	+41%	10.68
Oil, Gas and NGLs (per Boe)	$ 15.48	+2%	15.16	+35%	11.19
Absolute:					
Oil	$115,504	+44%	80,142	+45%	55,290
Gas	$139,018	+104%	68,049	+34%	50,732
NGLs	$ 19,338	+35%	14,367	+124%	6,404
Oil, Gas and NGLs	$273,860	+68%	162,558	+45%	112,426

	Canada				
	Year Ended December 31,				
	1997	1997 vs 1996	1996	1996 vs 1995	1995
	(Absolute Amounts in Thousands)				
Production					
Oil (MBbls)	950	N/A	-	N/A	-
Gas (MMcf)	8,312	N/A	-	N/A	-
NGLs (MBbls)	158	N/A	-	N/A	-
Oil, Gas and NGLs (MBoe)	2,493	N/A	-	N/A	-
Revenues					
Per Unit of Production:					
Oil (per Bbl)	$ 18.89	N/A	-	N/A	-
Gas (per Mcf)	$ 1.39	N/A	-	N/A	-
NGLs (per Bbl)	$ 15.28	N/A	-	N/A	-
Oil, Gas and NGLs (per Boe)	$ 12.79	N/A	-	N/A	-
Absolute:					
Oil	$17,941	N/A	-	N/A	-
Gas	$11,531	N/A	-	N/A	-
NGLs	$ 2,416	N/A	-	N/A	-
Oil, Gas and NGLs	$31,888	N/A	-	N/A	-

Oil Revenues 1997 vs. 1996 Oil revenues increased by $53.3 million in 1997. Production gains of 3.2 million barrels added $67.0 million of oil revenues in 1997. This increase was partially offset by a $13.7 million reduction in oil revenues caused by a $1.95 per barrel decrease in the average oil price in 1997.

The KMG-NAOS Properties acquired at the end of 1996 were the primary contributors to the increased oil production in 1997. These properties 1997 production totaled 3.1 million barrels. Approximately 2.1 million barrels of such production were in the U.S., while 1 million barrels were produced in Canada. Devon s other domestic properties produced 3.9 million barrels in 1997. This was an increase of 0.1 million barrels, or 3%, over the 1996 production of 3.8 million barrels.

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 1994 accounted for the majority of 1996's increased production. This field produced 1.1 million 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 2.5 million barrels in 1995 to 2.7 million barrels in 1996.

Gas Revenues 1997 vs. 1996 Gas revenues increased by $82.5 million in 1997. An increase in production of 33.6 Bcf added $64.0 million to 1997 s gas revenues. An increase of $0.26 per Mcf in the average price added $18.5 million to 1997 s gas revenues.

The KMG-NAOS Properties were responsible for the majority of the increased gas production in 1997. These properties produced 29.8 Bcf in 1997. Approximately 21.5 Bcf of such production was in the U.S., while 8.3 Bcf was produced in Canada. Devon s coal seam gas properties produced 17.6 Bcf in 1997 compared to 17.4 Bcf in 1996. Devon s other domestic properties produced 21.9 Bcf in 1997 compared to 18.3 Bcf in 1996.

Devon s coal seam properties averaged $2.13 per Mcf in 1997 compared to $1.72 per Mcf in 1996. The San Juan Basin Transaction added $8.4 million to coal seam gas revenues in 1997 compared to $10.3 million in 1996. The San Juan Basin Transaction increased the average coal seam gas price by $0.48 per Mcf in 1997 and $0.59 per Mcf in 1996.

Devon s domestic conventional gas properties averaged $2.34 per Mcf in 1997 compared to $2.08 per Mcf in 1996.

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. Coal seam gas revenues included $10.3 million in 1996 and $12.8 million in 1995 attributable to the San Juan Basin Transaction. This transaction increased the average coal seam gas price by $0.59 per Mcf in 1996 and $0.61 per Mcf in 1995.

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.

NGL Revenues 1997 vs. 1996 NGL revenues increased by $7.4 million in 1997. An increase in production of 674,000 barrels added $10.2 million to 1997 s revenues. This increase was partially offset by a $2.8 million reduction in NGL revenues caused by a $1.71 per barrel decrease in 1997 s average price.

The majority of the increased NGL production in 1997 was attributable to the KMG-NAOS Properties. These properties produced 339,000 barrels in the U.S. and 158,000 barrels in Canada in 1997.

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 NGL revenues. The remaining $3.8 million of increased revenues was attributable to increased production of 352,000 barrels in 1996.

Additional interests acquired in certain Wyoming properties in December 1995 and the first half of 1996 accounted for 214,000 barrels of the increased production in 1996. These Wyoming 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 that area from 69,000 barrels in 1995 to 95,000 barrels in 1996.

Other Revenues. 1997 vs. 1996 Other revenues increased by $5.9 million in 1997. Revenues from processing third party natural gas related to the KMG-NAOS Properties accounted for $3.3 million of the increase. An increase in interest income provided another $1.7 million of the increase in 1997 s other revenues.

1996 vs. 1995 Other revenue increased by $0.6 million in 1996. Increases in gains recognized from the disposal of non- oil and gas fixed assets and from settlements of gas contract claims accounted for most of this increase.

Expenses The details of the changes in pre-tax expenses between 1995 and 1997 are shown in the table below.

	Year Ended December 31, (Absolute Amounts in Thousands)				
	1997	1997 vs 1996	1996	1996 vs 1995	1995
Absolute:					
Production and operating expenses:					
Lease operating expenses	$ 65,655	+108%	31,568	+16%	27,289
Production taxes	17,924	+68%	10,658	+56%	6,832
Depreciation, depletion and amortization of oil and gas properties	82,413	+98%	41,538	+13%	36,640
Subtotal	165,992	+98%	83,764	+18%	70,761
Depreciation and amortization of non-oil and gas properties	2,894	+59%	1,823	+26%	1,450
General and administrative expenses	12,922	+42%	9,101	+8%	8,419
Interest expense	274	-95%	5,277	-25%	7,051
Distributions on preferred securities of subsidiary trust	9,717	+104%	4,753	N/A	-
Total	$191,799	+83%	104,718	+19%	87,681
Per Boe Produced:					
Production and operating expenses:					
Lease operating expenses	$ 3.25	+10%	2.95	+8%	2.72
Production taxes	0.89	-10%	0.99	+46%	0.68
Depreciation, depletion and amortization of oil and gas properties	4.08	+5%	3.88	+6%	3.65
Subtotal	8.22	+5%	7.82	+11%	7.05
Depreciation and amortization of non-oil <F1> and gas properties (1)	0.15	-12%	0.17	+21%	0.14
<F1> General and administrative expenses (1)	0.64	-25%	0.85	+1%	0.84

<F1>

Interest expense (1)	0.01	-98%	0.49	-30%	0.70
Distributions on preferred securities of subsidiary trust (1)	0.48	+9%	0.44	N/A	-
Total	$ 9.50	-3%	9.77	+12%	8.73

<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 1995 and 1997 are shown in the table below.

Total Year Ended December 31, (Absolute Amounts in Thousands)	1997	1997 vs 1996	1996	1996 vs 1995	1995
Absolute:					
Recurring lease operating expenses	$61,658	+118%	28,270	+19%	23,842
Well workover expenses	3,997	+21%	3,298	-4%	3,447
Production taxes	17,924	+68%	10,658	+56%	6,832
Total production and operating expenses	$83,579	+98%	42,226	+24%	34,121
Per Boe:					
Recurring lease operating expenses	$ 3.05	+16%	2.64	+11%	2.37
Well workover expenses	0.20	-35%	0.31	-11%	0.35
Production taxes	0.89	-10%	0.99	+46%	0.68
Total production and operating expenses	$ 4.14	+5%	3.94	+16%	3.40

Domestic Year Ended December 31, (Absolute Amounts in Thousands)	1997	1997 vs 1996	1996	1996 vs 1995	1995
Absolute:					
Recurring lease operating expenses	$54,969	+94%	28,270	+19%	23,842
Well workover expenses	3,143	-5%	3,298	-4%	3,447
Production taxes	17,646	+66%	10,658	+56%	6,832
Total production and operating expenses	$75,758	+79%	42,226	+24%	34,121
Per Boe:					
Recurring lease operating expenses	$ 3.10	+17%	2.64	+11%	2.37
Well workover expenses	0.18	-42%	0.31	-11%	0.35
Production taxes	1.00	+1%	0.99	+46%	0.68
Total production and operating expenses	$ 4.28	+9%	3.94	+16%	3.40

Canada Year Ended December 31, (Absolute Amounts in Thousands)	1997	1997 vs 1996	1996	1996 vs 1995	1995
Absolute:					
Recurring lease operating expenses	$ 6,689	N/A	-	N/A	-
Well workover expenses	854	N/A	-	N/A	-
Production taxes	278	N/A	-	N/A	-
Total production and operating expenses	$ 7,821	N/A	-	N/A	-
Per Boe:					

Recurring lease operating expenses	$ 2.68	N/A	-	N/A	-
Well workover expenses	0.35	N/A	-	N/A	-
Production taxes	0.11	N/A	-	N/A	-
Total production and operating expenses	$ 3.14	N/A	-	N/A	-

1997 vs. 1996 Recurring lease operating expenses increased by $33.4 million, or 118%, in 1997. The KMG-NAOS Properties accounted for $26.0 million of the increased expenses. Most of the remaining $7.4 million of 1997 s increase was due to wells which were drilled in 1997 and 1996.

Recurring expenses per Boe were up by $0.41 per Boe, or 16%, in 1997. This increase was caused by the reduction in the coal seam gas properties share of total production. The recurring operating costs per Boe for the coal seam gas properties are extremely low ($0.43 per Boe in 1997 and $0.32 per Boe in 1996). However, as production from these properties remained relatively flat and production from Devon s other properties increased in 1997, the coal seam gas properties percentage of overall production dropped from 27% in 1996 to only 15% in 1997. The result is that a larger percentage of Devon s production in 1997 was attributable to its conventional properties, which have a higher operating cost per Boe than the low-cost coal seam gas properties. The recurring operating costs per Boe for Devon s conventional properties were $3.50 per Boe in 1997 and 1996. Thus, the coal seam properties' costs rose only $0.11 per Boe in 1997 and the conventional properties' costs remained flat in 1997. However, since the conventional properties represented a larger percentage of Devon's total production in 1997 compared to 1996 (85% in 1997 compared to 73% in 1996), the result was a $0.41 per Boe increase in the overall rate.

Most taxing authorities collect production taxes on a fixed percentage of revenue basis. Therefore, as Devon s revenues have increased, so have production taxes. Production taxes increased 68% from $10.7 million in 1996 to $17.9 million in 1997. This increase was due to the 88% increase in combined oil, gas and NGL revenues in 1997.

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. Most of the remaining $1.7 million increase was 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. As explained above in the 1997 vs. 1996 discussion, the increase in the percentage of production attributable to conventional properties is also the cause of the increase in per Boe costs in 1996 compared to 1995. The recurring costs for the coal seam gas properties averaged $0.32 per Boe in 1996 and $0.24 per Boe in 1995. The recurring expenses of Devon's conventional oil and gas properties were $3.50 per Boe in 1996 and 1995. Thus, the coal seam properties' costs rose only $0.08 per Boe in 1996 and the conventional properties' costs per Boe remained flat in 1996. However, since the conventional properties represented a larger percentage of Devon's total production in 1996 compared to 1995 (73% in 1996 compared to 65% in 1995), the result was a $0.27 per Boe increase in the overall rate.

Production taxes increased 56% from $6.8 million in 1995 to $10.7 million in 1996. This increase was primarily due to the 45% increase in combined oil, gas and NGL revenues.

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.

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.

1997 vs. 1996 Oil and gas property related DD&A increased $40.9 million, or 98%, in 1997. Approximately $36.7 million of this increase was caused by the 88% increase in combined oil, gas and NGL production in 1997. The remaining $4.2 million of increase was caused by a 5% increase in the DD&A rate from $3.88 per Boe in 1996 to $4.08 per Boe in 1997.

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.

General and Administrative Expenses ("G&A") 1997 vs. 1996 G&A increased by $3.8 million, or 42%, in 1997. Employee salaries and related overhead costs, including insurance and pension expense, increased by $4.9 million. This increase was primarily related to the additional permanent and temporary personnel added at Devon s Oklahoma City and Calgary offices as a result of the addition of the KMG-NAOS Properties. The expansion in personnel also caused office-related costs such as rent, dues, travel, supplies, telephone, etc., to increase by $1.8 million in 1997.

The higher salary, overhead and office costs were partially offset by an increase in Devon s overhead reimbursements. As the operator of a property, Devon receives these reimbursements from the property s working interest owners. Devon records the reimbursements as reductions to G&A. Due to the addition of the KMG-NAOS Properties, many of which Devon operates, Devon s overhead reimbursements increased by $3.7 million in 1997.

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 joint interest owners in Devon-operated properties.

Interest Expense 1997 vs. 1996 Interest expense decreased $5.0 million, or 95%, in 1997. This decrease was caused by a drop in the average debt balance outstanding from $77.0 million in 1996 to $0.7 million in 1997. Devon issued $149.5 million of 6.5% Trust Convertible Preferred Securities (TCP Securities) in July, 1996. The proceeds from this issuance, along with cash flow from operations, were used to retire Devon s long-term bank debt early in 1997. (The TCP Securities are discussed further below.)

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 average 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 is being 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.

Distributions on Preferred Securities of Subsidiary Trust 1997 vs. 1996 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 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 on the TCP Securities accrue at the rate of 1.625% per quarter. Distributions in 1997 were $9.7 million compared to $4.8 million in 1996. The 1996 distribution total represented slightly less than two quarters distributions due to the issuance date occurring in July.

1996 vs. 1995 The TCP Securities were issued in July, 1996. The 1996 distributions of $4.8 million represented slightly less than two quarters' distributions due to the issuance date occurring in July.

Income Taxes 1997 vs. 1996 Devon s effective financial tax rate in 1997 was 38% compared to 41% in 1996. 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 a 1994 merger. Also, the 1997 rate was affected by certain tax aspects of the KMG-NAOS transaction and by Canadian income taxes which accrue at rates higher than the U.S. statutory rate of 35%. (The effective financial income tax rate for Devon's Canadian operations was 43% in 1997.)

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 federal statutory rate of 35% due to the effect of the state taxes, San Juan Basin Transaction and 1994 merger noted in the above paragraph.

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 $130.5 million of cash was spent in 1997 for capital expenditures, of which $124.6 million was related to the acquisition, drilling or development of oil and gas properties. Most of the drilling and development efforts in 1997 centered in the Permian Basin, which included 174 of the 295 oil and gas wells that Devon drilled during the year.

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. Quarterly dividends in 1997 were paid at the rate of $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 1997. Operating cash flow in 1997 totaled $168.7 million, a 94% increase compared to the $86.8 million of operating cash flow generated in 1996.

In addition to operating cash flow, Devon's credit lines have historically been an important source of capital and liquidity. However, 1997's increased operating cash flow allowed Devon to fund its 1997 capital expenditures and other cash uses without borrowing against its credit lines. At the end of 1997, Devon had $208 million of long-term credit lines, all of which was available for future use. Also, Devon has a $12.5 million Canadian dollars demand facility for its Canadian operations. All of this Canadian facility was also available at the end of 1997 for future use. (See Note 7 to the consolidated financial statements included elsewhere in this report for a detailed discussion of Devon's credit lines.)

1998 Estimates

The forward-looking statements provided in this discussion are based on management's examination of historical operating trends, the December 31, 1997 reserve reports of independent petroleum engineers and other data in Devon's possession or 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 and sale of oil and gas. These risks include, but are not limited to, price volatility, inflation or lack of availability of goods and services, environmental risks, drilling risks, regulatory changes, the uncertainty inherent in estimating future oil and gas production or reserves, and other risks as outlined below. Also, the financial results for Devon's Canadian operations, obtained in the KMG-NAOS transaction, are subject to currency exchange rate risks. Additional risks are discussed below in the context of line items most affected by such risks.

Specific Assumptions and Risks Related to Price and Production Estimates Prices for oil, natural gas and NGLs are determined primarily by prevailing market conditions. Market conditions for these products are influenced by regional and world-wide economic growth, weather and other substantially variable factors. These factors are beyond Devon s control and are difficult to predict. In addition to volatility in general, Devon's oil, gas and NGL prices may vary considerably due to differences between regional markets and demand for different grades of oil, gas and NGLs. 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. 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 significant 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 1998 will be substantially similar to those of 1997, unless otherwise noted. Given the general limitations expressed herein, Devon's forward-looking statements for 1998 are set forth below.

Oil Production and Relative Prices Devon expects its oil production in 1998 to total between 6.3 million barrels and 7.3 million barrels. Devon expects its net oil prices per barrel will average from between $0.20 to $0.45 above West Texas Intermediate posted prices in 1998.

Gas Production and Relative Prices Devon expects its total gas production in 1998 will be between 67.0 Bcf and 78.5 Bcf. It is expected that coal seam gas production will be between 19.0 Bcf and 22.2 Bcf. Canadian production in 1998 is estimated to be between 6.8 Bcf and 8.0 Bcf. Devon expects production from the remainder of its gas properties to total between 41.2 Bcf and 48.3 Bcf.

Devon expects its 1998 coal seam average price will be between $0.25 and $0.55 per Mcf less than Texas Gulf Coast spot averages. This includes an expected $0.40 to $0.45 per Mcf from the San Juan Basin Transaction. Devon's Canadian gas production is expected to average from between $0.80 to $1.05 less than Texas Gulf Coast spot averages. (These Canadian differentials are expressed in U.S. dollars, using the year- end 1997 exchange rate of $0.70 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 averages during 1998.

Devon had made firm commitments to sell approximately 12,700 Mcf per day of its coal seam gas production throughout 1998 at a fixed price of approximately $1.45 per Mcf, which equates to a price of approximately $2.04 per MMBtu. (The $1.45 per Mcf price includes the effect of adjusting for Btu content and is net of costs for transportation and removing carbon dioxide. This price excludes the expected $0.40 to $0.45 per Mcf benefit from the San Juan Basin Transaction.) The effect of these fixed price commitments has been included in the expected differential for coal seam gas discussed in the above paragraph. Devon has also made other commitments to sell certain quantities of its 1998 domestic conventional and Canadian gas production at fixed prices. However, such commitments to date are not expected to have a material effect on Devon's 1998 gas price differentials due to the limited quantities of gas per day involved.

NGL Production Devon expects its production of NGLs in 1998 to total between 1.3 million barrels and 1.5 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.

Oil, gas and NGL prices will have a direct effect on production taxes to be incurred in 1998. 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 uncertainty inherent in estimating future production and operating costs. Given these uncertainties, Devon estimates that 1998's total production and operating costs will be between $78.0 million and $90.5 million.

Depreciation, Depletion and Amortization The 1998 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 1998 compared to the costs incurred for such efforts, and the revisions to Devon's year-end 1997 reserve estimates which will be made during 1998.

The DD&A rate as of the beginning of 1998 was 4.08 per Boe. Assuming a 1998 rate of between $4.10 per Boe and $4.45 per Boe, 1998 oil and gas property related DD&A expense is expected to be $85 million to $93 million. Additionally, Devon expects its non-oil and gas property related DD&A to total between $3 million and $4 million in 1998.

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. 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 $13 million and $15 million in 1998.

Interest Expense Devon s management expects to fund substantially all of its anticipated expenditures during 1998 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 1998.

Distributions on TCP Securities TCP Securities are convertible into common shares of Devon at the option of the holder. Any conversions of the TCP Securities 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 1998.

Income Taxes Devon expects its financial income tax rate in 1998 to be between 34% and 38%. Regardless of the level of pre-tax earnings reported for financial purposes, Devon will have a minimum of approximately $2.0 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 1998 pre-tax earnings differs materially from what Devon currently expects, the actual financial income tax rate for 1998 could differ from the expected rate of 34% to 38%. Also, based on its current expectations of 1998 taxable income, Devon anticipates its current portion of 1998 income taxes will be between $12 million and $17 million. However, unanticipated revenue and earnings fluctuations could easily make these tax estimates inaccurate.

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 and, consequently, may increase or decrease total 1998 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 several major property transactions in recent years, these transactions are opportunity driven. Thus, Devon does not "budget", nor can it reasonably predict, the timing or size of such possible acquisitions, if any.

Given these limitations, Devon expects its 1998 capital expenditures for drilling and development efforts to total between $140 million and $160 million, including $8 million to $12 million in Canada. (Canadian amounts are expressed in U.S. dollars, using the year-end 1997 exchange rate of $0.70 U.S. dollar to $1.00 Canadian dollar.) Devon expects to spend $45 million to $60 million in 1998 for drilling, facilities and waterflood costs related to reserves classified as proved as of year-end 1997. Devon also plans to spend another $60 million to $70 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 32.3 million shares of common stock outstanding, 1998 dividends are expected to approximate $6.5 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 1998 is uncertain due to the factors affecting revenues and expenses cited above. However, Devon expects that its capital resources will be more than adequate to fund its anticipated capital expenditures.

Based on the expected level of 1998's capital expenditures and net cash provided by operations, Devon does not expect to rely on its existing 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 existing credit lines and/or seek to establish and utilize other sources of financing. The unused portion of existing credit lines at the end of 1997 consisted of $208 million of long-term credit facilities, and a $12.5 million Canadian dollars demand facility for Devon's 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.

Potential Reduction in Carrying Value of Oil and Gas Properties. Under the full cost method of accounting, the net book value of oil and gas properties, less related deferred income taxes, may not exceed a calculated "ceiling." The ceiling limitation is the discounted estimated after-tax future net revenues from proved oil and gas properties. The ceiling is imposed separately by country. In calculating future net revenues, current prices and costs are generally held constant indefinitely. The net book value is compared to the ceiling on a quarterly and annual basis. Any excess of the net book value above the ceiling is written off as an expense.

At December 31, 1997, the Company's net book value of oil and gas properties less deferred taxes was well below the calculated ceiling. This excess "cushion" was $146 million for the Company's U.S. properties and $18 million for its Canadian properties. By March 11, 1998 oil prices had declined significantly from year-end 1997 levels. There had also been a moderate decline in natural gas prices. Based on these decreases, Devon estimated that its ceiling value on March 11, 1998 was significantly lower than at year-end 1997. However, the estimated ceiling value was still greater than the book value of the Company's oil and gas properties less deferred taxes. Oil or gas price declines after March 11, 1998 could cause the ceiling value to fall below the recorded net book value. The result would be a reduction in the carrying value of the Company's oil and gas properties. Should this occur, the Company also would recognize a corresponding expense.

Impact of Recently Issued Accounting Standards Not Yet Adopted In June, 1997, the Financial Accounting Standards Board issued Statement of Financial Accounting Standards No. 130, Reporting Comprehensive Income. SFAS No. 130 is effective for fiscal years beginning after December 15, 1997. SFAS No. 130 establishes standards for reporting and display of comprehensive income and its components in a set of financial statements. It requires that all items that are required to be recognized under accounting standards as components of comprehensive income be reported in a financial statement that is displayed with the same prominence as other financial statements. The only component of comprehensive income that is not currently included in Devon s consolidated statements of operations is the currency translation adjustment reported as part of stockholders equity as of December 31, 1997. Devon will adopt SFAS No. 130 in 1998.

Also in June, 1997, Statement of Financial Accounting Standards No. 131, Disclosures about Segments of an Enterprise and Related Information, was issued. SFAS No. 131 is effective for periods beginning after December 15, 1997. SFAS No. 131 requires that publicly-traded entities report financial and descriptive information about reportable operating segments. Operating segments are components of an enterprise about which separate financial information is available that is evaluated regularly by the chief operating decision maker in deciding how to allocate resources and in assessing performance. Devon will adopt SFAS No. 131 in 1998. However, such adoption is not expected to have a material impact on Devon s current financial disclosures because Devon s oil and gas operations are expected to be the only reportable operating segment under SFAS No. 131 s definitions.

In January, 1997, the Securities and Exchange Commission issued Release #33-7386. This release requires enhanced description of accounting policies for derivative financial instruments and derivative commodity instruments in the footnotes to the financial statements. The release also requires quantitative and qualitative disclosures outside the financial statements about market risks inherent in market risk sensitive instruments including derivative financial instruments, derivative commodity instruments and other financial instruments. The requirements regarding accounting policy descriptions were effective for any fiscal period ending after June 15, 1997. However, because derivative financial or commodity instruments have not materially affected Devon's financial position, cash flows or results of operations, this part of the release did not affect Devon's 1997 disclosures. The quantitative and qualitative disclosures set forth in the release will be initially required in Devon's annual report on Form 10-K for the year ending December 31, 1998.

Impact of the Year 2000 Issue An issue exists for all companies that rely on computers as the year 2000 approaches. This is because historically many computer programs used only two digits to represent the year in dates. Therefore, without adequate modifications, many programs will not correctly identify the year 2000. Devon plans to install a Year 2000 Release of its commercial software during 1998. In-house modifications that have been previously made to the commercial software will also be upgraded at that time to be year 2000 compliant. Devon anticipates that it will be able to install the new commercial software release, upgrade its modifications and test the entire system with its existing internal programming staff. Therefore, future incremental expenses, if any, incurred to deal with the year 2000 issue are expected to be immaterial to Devon's future operating results.

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, 1997, 1996 and 1995, 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
January 26, 1998

DEVON ENERGY CORPORATION AND SUBSIDIARIES
Consolidated Balance Sheets

	December 31, 1997	1996	1995
Assets			
Current assets:			
Cash and cash equivalents	$ 42,064,344	9,401,350	8,897,891
Accounts receivable (Note 5)	47,507,805	29,580,306	14,400,295
Inventories	2,422,822	2,103,486	605,263
Prepaid expenses	799,923	688,752	222,135
Deferred income taxes (Note 8)	434,000	1,600,000	749,000
Total current assets	93,228,894	43,373,894	24,874,584
Property and equipment, at cost, based on the full cost method of accounting for oil and gas properties (Note 6)	1,103,320,502	974,805,756	631,437,904
Less accumulated depreciation, depletion and amortization	365,517,722	281,959,410	239,619,167
	737,802,780	692,846,346	391,818,737
Other assets	15,371,368	10,030,560	4,870,796
Total assets	$ 846,403,042	746,250,800	421,564,117
Liabilities and stockholders' equity			
Current liabilities:			
Accounts payable:			
Trade	9,628,890	4,861,428	3,868,458
Revenues and royalties due to others	11,531,296	10,569,960	7,322,418
Income taxes payable	4,901,940	4,705,447	1,364,070
Accrued expenses	4,750,699	3,503,420	3,003,943
Total current liabilities	30,812,825	23,640,255	15,558,889
Revenues and royalties due to others	2,862,794	1,259,129	889,173
Other liabilities (Notes 3 and 11)	18,177,130	10,325,999	8,623,057
Long-term debt (Note 7)	-	8,000,000	143,000,000
Deferred income taxes (Note 8)	101,474,000	81,121,000	34,452,000
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	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 32,318,895 in 1997, 32,141,295 in 1996, 22,111,896 in 1995	3,231,890	3,214,130	2,211,190
Additional paid-in capital	392,919,170	388,090,930	167,430,347
Retained earnings	149,946,232	81,099,357	49,399,461
Cumulative currency translation adjustment	(2,520,999)	-	-
Total stockholders' equity	543,576,293	472,404,417	219,040,998
Commitments and contingencies (Notes 11 and 12)			
Total liabilities and stockholders' equity	$ 846,403,042	746,250,800	421,564,117

See accompanying notes to consolidated financial statements.

DEVON ENERGY CORPORATION AND SUBSIDIARIES
Consolidated Statements of Operations

	Year Ended December 31, 1997	1996	1995
Revenues			
Oil sales	$133,445,231	80,142,073	55,289,819
Gas sales	150,548,871	68,049,478	50,732,158
Natural gas liquids sales	21,754,033	14,366,771	6,403,663
Other	7,391,733	1,458,562	877,185
Total revenues	313,139,868	164,016,884	113,302,825
Costs and expenses			
Lease operating expenses	65,655,074	31,568,428	27,288,755
Production taxes	17,923,815	10,657,814	6,832,507
Depreciation, depletion and amortization (Note 6)	85,306,868	43,361,029	38,089,783
General and administrative expenses	12,922,259	9,101,429	8,418,739
Interest expense	273,821	5,276,527	7,051,142
Distributions on preferred securities of subsidiary trust (Note 9)	9,717,502	4,753,125	-
Total costs and expenses	191,799,339	104,718,352	87,680,926
Earnings before income taxes	121,340,529	59,298,532	25,621,899
Income tax expense (Note 8)			
Current	25,202,000	6,709,000	4,495,000
Deferred	20,847,000	17,789,000	6,625,000
Total income tax expense	46,049,000	24,498,000	11,120,000
Net earnings	$ 75,291,529	34,800,532	14,501,899
Net earnings per average common share outstanding (Note 1):			
Basic	$2.34	1.57	0.66
Diluted	$2.17	1.52	0.65
Weighted average common shares outstanding - basic (Note 1)	32,215,745	22,159,507	22,073,550

See accompanying notes to consolidated financial statements.

DEVON ENERGY CORPORATION AND SUBSIDIARIES
Consolidated Statements of Stockholders' Equity

	Year Ended December 31, 1997	1996	1995
Common stock			
Balance, beginning of year	3,214,130	2,211,190	2,205,100
Par value of common shares issued	17,760	1,002,940	6,090
Balance, end of year	3,231,890	3,214,130	2,211,190
Additional paid-in capital			
Balance, beginning of year	388,090,930	167,430,347	166,654,305
Common shares issued, net of issuance costs	3,628,240	220,660,583	776,042
Tax benefit related to employee stock options	1,200,000	-	-
Balance, end of year	392,919,170	388,090,930	167,430,347
Retained earnings			
Balance, beginning of year	81,099,357	49,399,461	37,546,460
Dividends	(6,444,654)	(3,100,636)	(2,648,898)
Net earnings	75,291,529	34,800,532	14,501,899
Balance, end of year	149,946,232	81,099,357	49,399,461
Cumulative currency translation adjustment			
Balance, beginning of year	-	-	-
Net change	(2,520,999)	-	-
Balance, end of year	(2,520,999)	-	-
Total stockholders' equity, end of year	$543,576,293	472,404,417	219,040,998

See accompanying notes to consolidated financial statements.

DEVON ENERGY CORPORATION AND SUBSIDIARIES
Consolidated Statements of Cash Flows

	Year Ended December 31, 1997	1996	1995
Cash flows from operating activities			
Net earnings	$ 75,291,529	34,800,532	14,501,899
Adjustments to reconcile net earnings to net cash provided by operating activities:			
Depreciation, depletion and amortization	85,306,868	43,361,029	38,089,783
(Gain) loss on sale of assets	(192,278)	(3,930)	273,238
Deferred income taxes	20,847,000	17,789,000	6,625,000
Changes in assets and liabilities net of effects of acquisitions of businesses (Note 2):			
(Increase) decrease in:			
Accounts receivable	(17,835,233)	(15,470,528)	1,213,877
Inventories	(344,286)	(176,286)	(70,937)
Prepaid expenses	(116,932)	(466,617)	342,236
Other assets	(874,496)	(1,032,653)	677,238
Increase (decrease) in:			
Accounts payable	3,394,868	3,370,474	(430,736)
Income taxes payable	445,493	3,341,377	1,364,070
Accrued expenses	1,078,012	399,477	(221,550)
Revenues and royalties due to others	1,603,665	369,956	(1,793,909)
Long-term other liabilities	117,700	519,978	705,636
Net cash provided by operating activities	168,721,910	86,801,809	61,275,845
Cash flows from investing activities			
Proceeds from sale of property and equipment	1,711,769	4,037,480	9,427,401
Capital expenditures	(130,468,542)	(98,854,846)	(117,593,897)
Payments made for acquisition of business	-	-	(2,391,484)
Increase in other assets	(2,583,920)	-	-
Net cash used in investing activities	(131,340,693)	(94,817,366)	(110,557,980)
Cash flows from financing activities			
Proceeds from borrowings on revolving line of credit	1,847,750	29,000,000	52,000,000
Principal payments on revolving line of credit	(9,843,750)	(164,000,000)	(7,000,000)
Issuance of common stock, net of issuance costs	3,646,000	577,483	782,132
Issuance of preferred securities of subsidiary trust, net of issuance costs	-	144,665,205	-
Dividends paid on common stock	(6,444,654)	(3,100,636)	(2,648,898)
Increase in long-term other liabilities (Note 3)	6,268,085	1,376,964	6,710,421
Net cash provided (used) by financing activities	(4,526,569)	8,519,016	49,843,655
Effect of exchange rate changes on cash	(191,654)	-	-
Net increase in cash and cash equivalents	32,662,994	503,459	561,520
Cash and cash equivalents at beginning of year	9,401,350	8,897,891	8,336,371
Cash and cash equivalents at end of year	$ 42,064,344	9,401,350	8,897,891

See accompanying notes to consolidated financial statements.

Notes to Consolidated Financial Statements December 31, 1997, 1996 and 1995

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.

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 1997 and 1996, there was one purchaser, Aquila Energy Marketing Corporation ("Aquila"), who accounted for over 10% of Devon's gas sales. Aquila accounted for 46% of Devon's 1997 gas sales and 45% of 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. - 16%.

Income Taxes

Devon accounts for income taxes using the asset and liability method, whereby deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of assets and liabilities and their respective tax bases, as well as the future tax consequences attributable to the future utilization of existing tax net operating loss and other types of carryforwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences and carryforwards are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date.

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

In February, 1997, the Financial Accounting Standards Board issued Statement of Financial Accounting Standards No. 128, Earnings Per Share. SFAS No. 128 revised the previous calculation methods and presentations of earnings per share. The statement required that all prior-period earnings per share data be restated. Devon adopted SFAS No. 128 in the fourth quarter of 1997 as permitted by the statement. The effect of adopting SFAS No. 128 was not material to Devon s prior period earnings per share data. The previously reported amounts for earnings per share assuming no dilution (now replaced by "basic earnings per share" under SFAS No. 128) were not affected for any prior periods. Restated "diluted" earnings per share were $0.01 per share less than the previously reported "earnings per share assuming full dilution" for each of the following periods: the years 1995 and 1994 and the second and third quarters of 1996 (as disclosed in Note 15).

Under the provisions of SFAS No. 128, basic earnings per share is computed by dividing income available to common stockholders by the weighted average number of common shares outstanding for the period. Diluted earnings per share reflects the potential dilution that could occur if Devon s outstanding stock options were exercised (calculated using the treasury stock method) or if Devon s Trust Convertible Preferred Securities were converted to common stock.

The following tables reconcile the net earnings and common shares outstanding used in the calculations of basic and diluted net earnings per share for the years 1997, 1996 and 1995.

	Net Earnings	Common Shares Outstanding	Net Earnings Per Share
Year ended December 31, 1997:			
Basic earnings per share	$75,291,529	32,215,745	2.34
Dilutive effect of:			
Potential common shares issuable upon the conversion of Trust Convertible Preferred securities (the increase in net earnings is net of income tax expense of $3,853,000)	6,025,955	4,901,507	
Potential common shares issuable upon the exercise of employee stock options	-	408,477	
Diluted earnings per share	$81,317,484	37,525,729	2.17

Year ended December 31, 1996:			
Basic earnings per share	34,800,532	22,159,507	1.57
Dilutive effect of:			
Potential common shares issuable upon the conversion of Trust Convertible Preferred securities (the increase in net earnings is net of income tax expense of $1,837,000)	2,997,779	2,383,793	
Potential common shares issuable upon the exercise of employee stock options	-	254,352	
Diluted earnings per share	$37,798,311	24,797,652	1.52
Year ended December 31, 1995:			
Basic earnings per share	14,501,899	22,073,550	0.66
Dilutive effect of potential common shares issuable upon the exercise of employee stock options	-	130,621	
Diluted earnings per share	$14,501,899	22,204,171	0.65

Dividends

Dividends on common stock were paid in 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 and all four quarters of 1997.

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 did not have a material impact on Devon's financial position or results of operations.

Reclassifications

Certain items in the 1996 and 1995 consolidated balance sheets and statements of cash flows have been reclassified to correspond with the 1997 presentation.

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 $30.3 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 $195.1 million allocated to proved oil and gas reserves, $29.0 million allocated to undeveloped leasehold acquired, $0.6 million allocated to inventories and other assets acquired and $3.1 million allocated to certain assumed liabilities. Including the additional $30.3 million of deferred tax liability, $220.0 million was allocated to proved reserves and $34.4 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 were approximately 36% oil and natural gas liquids and 64% natural gas. Included in the acquired reserves were certain proved undeveloped reserves, for which Devon expected 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.

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:	
Basic	$2.16
Diluted	$2.09
Weighted average common shares outstanding - basic	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:				
Basic	$0.66			0.86
Diluted	$0.65			0.85

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 1997 were equal to approximately $1.05 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 nine 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, 1997, 1996 and 1995, Devon received $11.4 million, $11.5 million and $13.9 million, respectively, related to the credits. Of these amounts, $8.5 million, $10.3 million and $12.8 million were recorded as additional gas sales in 1997, 1996 and 1995, respectively, and $2.9 million, $1.2 million and $1.1 million were recorded as an addition to liabilities in 1997, 1996 and 1995, respectively, as discussed in the following paragraph. Based on the reserves estimated at December 31, 1997, and an assumed annual inflation factor of 2%, Devon estimates it will receive total tax credit payments of approximately $49 million from 1998 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 is being increased over time to reflect the expected option purchase price. As the purchase price increases, a portion of the tax credit payments received by Devon is added to the liability. As stated above, for the years ended December 31, 1997, 1996 and 1995, $2.9 million, $1.2 million and $1.1 million, respectively, of the total amount received for tax credit payments were added to the liability. On December 31, 1997, Devon exercised its option to reacquire approximately 20% of the properties for approximately $1.9 million. The other party to the production payment paid Devon $5.3 million in 1997 in return for Devon agreeing not to exercise its option on the remaining 80% of the properties through the end of 1997. (This agreement does not limit Devon's right to exercise its option in 1998 or beyond.) The $5.3 million that Devon received, net of the $1.9 million paid for the partial repurchase, was added to the repurchase liability in 1997. The repurchase liability totaled $14.2 million at the end of 1997.

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 $14.2 million of other liabilities recorded as of year-end 1997, does not include any amount related to such reserves.

4. Supplemental Cash Flow Information

Cash payments for interest in 1997, 1996 and 1995 were approximately $0.6 million, $5.5 million and $6.7 million, respectively. Cash payments for federal, state and foreign income taxes in 1997, 1996 and 1995 were approximately $25.0 million, $3.4 million and $2.2 million, respectively.

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

Value of common stock issued	$221,576,040
Liabilities assumed	3,098,691
Deferred tax liability created	30,308,000
Fair value of assets acquired	$254,982,731

5. Accounts Receivable

The components of accounts receivable included the following:

	December 31, 1997	1996	1995
Oil, gas and natural gas liquids revenue accruals	$32,643,633	24,200,047	11,169,313
Joint interest billings	11,742,554	4,318,764	2,962,037
Other	3,521,618	1,461,495	493,945
	47,907,805	29,980,306	14,625,295
Allowance for doubtful accounts	(400,000)	(400,000)	(225,000)
Net accounts receivable	$47,507,805	29,580,306	14,400,295

6. Property and Equipment

Property and equipment included the following:

	December 31, 1997	1996	1995
Oil and gas properties:			
Subject to amortization	$1,024,624,931	899,827,749	604,227,702
Not subject to amortization:			
Acquired in 1997	9,476,111	-	-
Acquired in 1996	27,906,918	35,141,800	-
Acquired in 1995	3,916,088	5,034,942	5,635,170
Acquired in 1994	870,664	1,001,291	1,001,427
Acquired in 1993	4,026,995	5,204,995	5,556,977
Acquired in 1992	7,814,255	8,113,899	8,257,985
Accumulated depreciation, depletion and amortization	(361,055,425)	(278,923,340)	(237,385,785)
Net oil and gas properties	717,580,537	675,401,336	387,293,476
Other property and equipment	24,684,540	20,481,080	6,758,643
Accumulated depreciation and amortization	(4,462,297)	(3,036,070)	(2,233,382)
Net other property and equipment	20,222,243	17,445,010	4,525,261
Property and equipment, net of accumulated depreciation, depletion and amortization	$ 737,802,780	692,846,346	391,818,737

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

Year Ended December 31, 1997	1996	1995

Depreciation, depletion and amortization of oil and gas properties	$82,413,245	41,537,555	36,639,753
Depreciation and amortization of other property and equipment	2,328,461	1,337,420	1,045,978
Amortization of other assets	565,162	486,054	404,052
Total expense	$85,306,868	43,361,029	38,089,783

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, 1997, was $208 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. No amounts were borrowed under the credit lines at the end of 1997. The average interest rates on the outstanding debt at the end of 1996 and 1995 were 6.19% and 6.64%, 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, 2000. Thereafter, the maximum loan amount will be reduced by 8.33% every three months until August 31, 2003. 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, 1997, Devon was in compliance with such covenants and restrictions.

Devon also has a demand revolving operating credit facility with a Canadian bank. This facility is unsecured and is utilized for general corporate purposes related to Devon's 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 1997 or 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 $0.4 million of the gain was recognized in 1997, and $0.2 million 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, 1997, 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	2007 - 2008	$ 7,300,000
Net operating loss - various states	1998 - 2011	$10,200,000

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

The earnings before income taxes and the components of income tax expense for the years 1997, 1996 and 1995 were as follows:

	Year Ended December 31, 1997	1996	1995
Earnings before income taxes:			
United States	$106,905,365	59,298,532	25,621,899
Canada	14,435,164	-	-
Total	$121,340,529	59,298,532	25,621,899
Current income tax expense:			
Federal	$18,659,000	6,147,000	4,155,000
State	2,521,000	562,000	340,000
Canada	4,022,000	-	-
Total current tax expense	25,202,000	6,709,000	4,495,000

Deferred income tax expense:			
Federal	17,025,000	14,185,000	5,463,000
State	1,578,000	3,604,000	1,162,000
Canada	2,244,000	-	-
Total deferred tax expense	20,847,000	17,789,000	6,625,000
Total income tax expense	$46,049,000	24,498,000	11,120,000

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,		
	1997	1996	1995
Federal statutory tax rate	35%	35%	35%
Nonconventional fuel source credits	(1)	-	(1)
State income taxes	3	5	4
Taxation on foreign operations	1	-	-
Effect of San Juan Basin Transaction	-	2	4
Other	-	(1)	1
Effective income tax rate	38%	41%	43%

The tax effects of temporary differences that gave rise to significant portions of the deferred tax assets and liabilities at December 31, 1997, 1996 and 1995 are presented below:

	December 31,		
	1997	1996	1995
Deferred tax assets:			
Net operating loss carryforwards	$ 2,909,000	5,314,000	6,082,000
Statutory depletion carryforwards	-	412,000	2,287,000
Investment tax credit carryforwards	19,000	42,000	85,000
Minimum tax credit carryforwards	-	5,624,000	5,576,000
Production payments	18,504,000	19,685,000	24,770,000
Other	2,932,000	2,613,000	1,966,000
Total gross deferred tax assets	24,364,000	33,690,000	40,766,000
Less valuation allowance	100,000	100,000	100,000
Net deferred tax assets	24,264,000	33,590,000	40,666,000
Deferred tax liabilities:			
Property and equipment, principally due to differences in depreciation, and the expensing of intangile drilling costs for tax purposes	(123,783,000)	(113,111,000)	(74,369,000)
Other	(1,521,000)	-	-
Total deferred tax liabilities	(125,304,000)	(113,111,000)	(74,369,000)
Net deferred tax liability	$(101,040,000)	(79,521,000)	(33,703,000)

As shown in the above schedule, Devon has recognized $24.3 million of net deferred tax assets as of December 31, 1997. Such amount consists almost entirely of $2.9 million of various carryforwards available to offset future income taxes, and $18.5 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 2007, and state net operating loss carryforwards which expire primarily between 1999 and 2011. 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 1998 and 2001. 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, 1997, related to depletion carryforwards acquired in a 1994 merger.

The $18.5 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 $18.5 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, 1997 and 1996 was approximately $218.8 million and $196.6 million, respectively, as compared to the book value of $149.5 million. These fair values were based on quoted prices at which TCP Securities were purchased and sold on December 31, 1997 and 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, 1997, 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 three stock option plans adopted in 1988, 1993 and 1997 ("the 1988 Plan", "the 1993 Plan" and "the 1997 Plan"). Options granted under the 1988 Plan and 1993 Plan remain exercisable by the employees owning such options, but no new options will be granted under these plans. At December 31, 1997, 12 participants held the 251,100 options outstanding under the 1988 Plan, and 23 participants held the 806,300 options outstanding under the 1993 Plan.

On May 21, 1997, Devon's stockholders adopted the 1997 Plan and reserved two million shares of Common Stock for issuance thereunder. Approximately 30 employees and eight members of the board of directors were eligible to participate in the 1997 Plan at year-end 1997.

The exercise price of stock options granted under the 1997 Plan may not be less than the estimated fair market value of the stock at the date of grant, plus 10% if the grantee owns or controls more than 10% of the total voting stock of Devon prior to the grant. Options granted are exercisable during a period established for each grant, which period may not exceed 10 years from the date of grant. Under the 1997 Plan, the grantee must pay the exercise price in cash or in Common Stock, or a combination thereof, at the time that the option is exercised. The 1997 Plan is administered by a committee comprised of non- management members of the Board of Directors. The 1997 Plan expires on April 25, 2007. As of December 31, 1997, seven participants (all of whom are non-management members of the Board of Directors) held the 21,000 options outstanding under the 1997 Plan. There were 1,979,000 options available for future grants as of December 31, 1997.

A summary of the status of Devon's stock option plans as of December 31, 1995, 1996 and 1997, 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, 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
Options granted	54,000	$34.584		
Options exercised	(177,600)	$20.529		
Balance at December 31, 1997	1,078,400	$24.320	824,500	$23.257

The weighted average fair values of options granted during 1997, 1996 and 1995 were $13.74, $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 Black-Scholes Option Pricing Model with the following assumptions for 1997, 1996 and 1995, respectively:
risk-free interest rates of 6.3%, 6.3% and 5.5%; dividend yields of 0.6%, 0.6% and 0.5%; expected lives of five years for each period; and volatility of the price of the underlying common stock of 33.8%, 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, 1997:

	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	90,800	3.7 years	$ 9.677	90,800	$ 9.677
$18-$21	150,300	6.9 years	$18.098	120,900	$18.106
$23-$26	539,800	6.8 years	$23.799	451,000	$23.826
$32-$37	297,500	9.0 years	$32.878	161,800	$33.138
	1,078,400	7.2 years	$24.320	824,500	$23.257

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 1997, 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,		
	1997	1996	1995
Net earnings:			
As reported	$75,291,529	34,800,532	14,501,899
Pro forma	$74,564,309	34,016,571	13,540,052
Net earnings per share:			
As reported:			
Basic	$2.34	1.57	0.66
Diluted	$2.17	1.52	0.65

Pro forma:			
Basic	$2.31	1.54	0.61
Diluted	$2.15	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,		
	1997	1996	1995
Actuarial present value of benefit obligations:			
Accumulated benefit obligation:			
Vested	$(4,630,000)	(3,619,000)	(3,500,000)
Nonvested	(1,021,000)	(741,000)	(654,000)
Total	$(5,651,000)	(4,360,000)	(4,154,000)
Projected benefit obligation for service rendered to date	(6,690,000)	(5,122,000)	(4,782,000)
Plan assets at fair value, primarily investments in mutual funds	6,036,000	5,022,000	4,227,000
Plan assets less than projected benefit obligation	(654,000)	(100,000)	(555,000)
Unrecognized prior service cost (benefit)	(105,000)	(131,000)	(154,000)
Unrecognized net loss from past experience different from that assumed, and effects of changes in assumptions	1,276,000	519,000	921,000
Prepaid pension expense	$ 517,000	288,000	212,000

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

	December 31,		
	1997	1996	1995
Actuarial present value of benefit obligations:			
Accumulated benefit obligation:			
Vested	$(4,039,000)	(1,960,000)	(1,658,000)
Nonvested	(237,000)	(279,000)	(255,000)
Total	(4,276,000)	(2,239,000)	(1,913,000)

Projected benefit obligation for service rendered to date	(4,969,000)	(2,907,000)	(2,245,000)
Plan assets at fair value	-	-	-
Plan assets less than projected benefit obligation	(4,969,000)	(2,907,000)	(2,245,000)
Unrecognized prior service cost	2,078,000	1,235,000	1,354,000
Unrecognized net loss from past experience different from that assumed, and effects of changes in assumptions	1,172,000	446,000	185,000
Accrued pension expense	(1,719,000)	(1,226,000)	(706,000)
Additional minimum liability	(2,557,000)	(1,013,000)	(1,207,000)
Total pension liability	$(4,276,000)	(2,239,000)	(1,913,000)

The $4.3 million, $2.2 million and $1.9 million total pension liability of the Supplementary Plan as of December 31, 1997, 1996 and 1995, respectively, are included in long-term other liabilities on the accompanying consolidated balance sheets. The additional minimum liabilities of $2.6 million, $1.0 million and $1.2 million at year-end 1997, 1996 and 1995, respectively, are offset by intangible assets of the same amount. 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,		
	1997	1996	1995
Service cost - benefits earned during the period	$ 706,000	557,000	362,000
Interest cost on projected benefit obligation	747,000	569,000	446,000
Actual return on plan assets	(369,000)	(453,000)	(536,000)
Net amortization and deferral	177,000	231,000	345,000
Net periodic pension expense	$1,261,000	904,000	617,000

The weighted average discount rate used in determining the actuarial present value of the projected benefit obligation in 1997, 1996 and 1995 was 7.0%, 7.5% and 7.25%, 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% for all three years.

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 $451,000, $188,000 and $170,000 for the years ended December 31, 1997, 1996 and 1995, 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 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 each year for 1997 and 1996 taxes which were paid monthly throughout such years, 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. The State of New Mexico in 1997 denied Devon's initial refund application made through the normal administrative processes. Subsequently, in late 1997, Devon filed 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 $1.3 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, 1997:

Year ending December 31,	
1998	$ 555,000
1999	402,000
2000	326,000
2001	88,000
2002	40,000

Total minimum lease payments required	$1,411,000

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

1997	$1,130,896
1996	$ 572,177
1995	$ 546,388

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,		
	1997	1996	1995
Property acquisition costs:			
Proved, excluding deferred income taxes	$10,997,000	199,655,000	47,316,000
Deferred income taxes	2,379,000	22,557,000	-
Total proved, including deferred income taxes	$ 13,376,000	222,212,000	47,316,000
Unproved, excluding deferred income taxes	$ 8,734,000	29,673,000	4,529,000
Deferred income taxes	(100,000)	5,472,000	-
Total unproved, including deferred income taxes	8,634,000	35,145,000	4,529,000
Exploration costs	$19,169,000	2,708,000	7,174,000
Development costs	$87,394,000	73,468,000	56,253,000

Domestic			
	Year Ended December 31,		
	1997	1996	1995
Property acquisition costs:			
Proved, excluding deferred income taxes	$10,891,000	150,546,000	47,316,000
Deferred income taxes	2,084,000	15,257,000	-
Total proved, including deferred income taxes	$12,975,000	165,803,000	47,316,000
Unproved, excluding deferred income taxes	$ 7,582,000	26,073,000	4,529,000
Deferred income taxes	(100,000)	5,472,000	-
Total unproved, including deferred income taxes	7,482,000	31,545,000	4,529,000
Exploration costs	$18,326,000	2,708,000	7,174,000
Development costs	$79,943,000	73,468,000	56,253,000

Canada			
	Year Ended December 31,		
	1997	1996	1995
Property acquisition costs:			
Proved, excluding deferred income taxes	$ 106,000	49,109,000	-
Deferred income taxes	295,000	7,300,000	-
Total proved, including deferred income taxes	$ 401,000	56,409,000	-
Unproved	$ 1,152,000	3,600,000	-
Exploration costs	$ 843,000	-	-
Development costs	$ 7,451,000	-	-

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 $4.1 million, $2.9 million and $2.7 million in the years 1997, 1996 and 1995, respectively.

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

During 1997, various uncertainties that existed at year-end 1996 regarding the tax basis and liabilities assumed in the KMG-NAOS transaction were resolved. This resulted in an additional $5.5 million being allocated in 1997 to the proved properties acquired in the 1996 KMG-NAOS transaction. Of this amount, $3.1 million was for liabilities assumed and $2.4 million was for additional deferred tax liabilities created. This additional $5.5 million is included in the above table of costs incurred in 1997. The resolution of the uncertainties also resulted in a reduction of $0.1 million in 1997 to the deferred tax liabilities originally allocated in 1996 to the KMG-NAOS unproved properties.

Results of Operations for Oil and Gas Producing Activities

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

	Total Year Ended December 31,		
	1997	1996	1995
Oil, gas and natural gas liquids sales	$305,748,000	162,558,000	112,425,000
Production and operating expenses	(83,579,000)	(42,226,000)	(34,121,000)
Depreciation, depletion and amortization	(82,413,000)	(41,538,000)	(36,640,000)
Income tax expense	(51,050,000)	(27,796,000)	(15,536,000)
Results of operations for oil and gas producing activities	$ 88,706,000	50,998,000	26,128,000
Depreciation, depletion and amortization per equivalent barrel of production	$4.08	3.88	3.65

	Domestic Year Ended December 31,		
	1997	1996	1995
Oil, gas and natural gas liquids sales	$273,860,000	162,558,000	112,425,000
Production and operating expenses	(75,758,000)	(42,226,000)	(34,121,000)
Depreciation, depletion and amortization	(73,091,000)	(41,538,000)	(36,640,000)
Income tax expense	(44,648,000)	(27,796,000)	(15,536,000)
Results of operations for oil and gas producing activities	$ 80,363,000	50,998,000	26,128,000
Depreciation, depletion and amortization per equivalent barrel of production	$4.13	3.88	3.65

	Canada Year Ended December 31,		
	1997	1996	1995
Oil, gas and natural gas liquids sales	$ 31,888,000	-	-
Production and operating expenses	(7,821,000)	-	-
Depreciation, depletion and amortization	(9,322,000)	-	-
Income tax expense	(6,402,000)	-	-
Results of operations for oil and gas producing activities	$ 8,343,000	-	-
Depreciation, depletion and amortization per equivalent barrel of production	$3.74	-	-

As previously discussed, the above tables 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. Shown below are 1997 domestic and Canadian total revenues and net earnings, including all revenues and all costs and expenses, as well as total assets.

	Domestic	Canada	Total
As of or for the Year Ended December 31, 1997:			
Total revenues	$278,834,000	34,306,000	313,140,000
Net earnings	$ 67,123,000	8,169,000	75,292,000
Total assets	$776,134,000	70,269,000	846,403,000

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, 1997. Approximately 92%, 94% and 92%, of the respective year-end 1997, 1996 and 1995 domestic proved reserves were calculated by the independent petroleum consultants of LaRoche Petroleum Consultants, Ltd. The remaining percentages of domestic reserves are based on Devon's own estimates. All of the 1997 and 1996 Canadian proved reserves were calculated by the independent petroleum consultants of AMH Group Ltd.

	Total		
	Oil (Bbls)	Gas (Mcf)	Natural Gas Liquids (Bbls)
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
Revisions of estimates	(1,520,000)	(17,173,000)	1,614,000
Extensions and discoveries	8,517,000	106,608,000	301,000
Purchase of reserves	1,126,000	992,000	16,000
Production	(7,005,000)	(69,327,000)	(1,626,000)
Sale of reserves	(156,000)	(615,000)	(3,000)
Proved reserves as of December 1997	68,443,000	616,004,000	12,881,000
Proved developed reserves as of:			
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
December 31, 1997	60,165,000	506,374,000	12,098,000

	Domestic		
	Oil (Bbls)	Gas (Mcf)	Natural Gas Liquids (Bbls)
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
Revisions of estimates	(1,358,000)	(21,124,000)	1,531,000
Extensions and discoveries	7,394,000	94,925,000	301,000
Purchase of reserves	1,126,000	992,000	16,000
Production	(6,055,000)	(61,015,000)	(1,468,000)
Sale of reserves	(156,000)	(615,000)	(3,000)
Proved reserves as of December 31, 1997	60,902,000	567,824,000	12,072,000
Proved developed reserves as of:			
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

December 31, 1997	53,059,000	462,082,000	11,289,000

	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
Revisions of estimates	(162,000)	3,951,000	83,000
Extensions and discoveries	1,123,000	11,683,000	-
Purchase of reserves	-	-	-
Production	(950,000)	(8,312,000)	(158,000)
Sale of reserves	-	-	-
Proved reserves as of December 31, 1997	7,541,000	48,180,000	809,000
Proved developed reserves as of			
December 31, 1996	7,530,000	40,858,000	884,000
December 31, 1997	7,106,000	44,292,000	809,000

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,		
	1997	1996	1995
Future cash inflows	$2,516,923,000	3,989,582,000	1,476,418,000
Future costs:			
Development	(88,292,000)	(54,133,000)	(52,327,000)
Production	(866,609,000)	(1,071,913,000)	(496,279,000)
Future income tax expense	(317,064,000)	(785,702,000)	(153,431,000)
Future net cash flows	1,244,958,000	2,077,834,000	774,381,000
10% discount to reflect timing of cash flows	(518,105,000)	(901,617,000)	(328,481,000)
Standardized measure of discounted future net cash flows	$ 726,853,000	1,176,217,000	445,900,000
Discounted future net cash flows before income taxes	$ 913,073,000	1,621,992,000	534,248,000

	Domestic December 31,		
	1997	1996	1995
Future cash inflows	$2,304,602,000	3,712,956,000	1,476,418,000
Future costs:			
Development	(83,350,000)	(54,064,000)	(52,327,000)
Production	(806,130,000)	(1,013,750,000)	(496,279,000)
Future income tax expense	(269,880,000)	(713,182,000)	(153,431,000)
Future net cash flows	1,145,242,000	1,931,960,000	774,381,000
10% discount to reflect timing of cash flows	(481,263,000)	(846,174,000)	(328,481,000)
Standardized measure of discounted future net cash flows	$ 663,979,000	1,085,786,000	445,900,000
Discounted future net cash flows before income taxes	$ 820,448,000	1,486,603,000	534,248,000

	Canada December 31,		
	1997	1996	1995
Future cash inflows	$212,321,000	276,626,000	-
Future costs:			

Development	(4,942,000)	(69,000)	-
Production	(60,479,000)	(58,163,000)	-
Future income tax expense	(47,184,000)	(72,520,000)	-
Future net cash flows	99,716,000	145,874,000	-
10% discount to reflect timing of cash flows	(36,842,000)	(55,443,000)	-
Standardized measure of discounted future net cash flows	$ 62,874,000	90,431,000	-
Discounted future net cash flows before income taxes	$ 92,625,000	135,389,000	-

Future cash inflows are computed by applying year-end prices (averaging $16.93 per barrel of oil, adjusted for transportation and other charges, $1.89 per Mcf of gas and $12.42 per barrel of natural gas liquids at December 31, 1997) 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 $1.89 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 $35.2 million related to these tax credit payments from 1998 through 2002. This amount has been calculated using the assumption that the year-end 1997 tax credit rate of $1.05 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.

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,		
	1997	1996	1995
Beginning balance	$1,176,217,000	445,900,000	358,206,000
Sales of oil, gas and natural gas liquids, net of production costs	(222,169,000)	(120,332,000)	(78,304,000)
Net changes in prices and production costs	(723,385,000)	519,456,000	60,498,000
Extensions, discoveries, and improved recovery, net of future development costs	52,566,000	42,522,000	22,308,000
Purchase of reserves, net of future development costs	7,696,000	576,234,000	50,000,000
Development costs incurred during the period which reduced future development costs	27,883,000	44,332,000	43,810,000
Revisions of quantity estimates	(10,044,000)	40,905,000	7,397,000
Sales of reserves in place	(1,395,000)	(6,499,000)	(7,933,000)
Accretion of discount	162,199,000	53,425,000	39,821,000
Net change in income taxes	259,555,000	(357,427,000)	(48,347,000)
Other, primarily changes in timing	(2,270,000)	(62,299,000)	(1,556,000)
Ending balance	$ 726,853,000	1,176,217,000	445,900,000

15. Supplemental Quarterly Financial Information
(Unaudited)

Following is a summary of the unaudited interim results of operations for the years ended December 31, 1997 and 1996:

			1997		
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Full Year
Oil, gas and natural gas liquids sales	$86,572,042	67,759,826	70,517,534	80,898,733	305,748,135
Total revenues	$87,899,646	69,651,782	72,860,503	82,727,937	313,139,868
Net earnings	$25,225,546	14,829,990	16,305,960	18,930,033	75,291,529
Net earnings per share:					
Basic	$0.78	0.46	0.51	0.59	2.34
Diluted	$0.71	0.44	0.47	0.54	2.17

	1996				
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Full Year
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:					
Basic	$0.25	0.31	0.35	0.66	1.57
Diluted	$0.25	0.30	0.34	0.59	1.52

The above amounts for diluted net earnings per share for the second and third quarters of 1996 have been restated from the amounts previously reported as "net earnings per share assuming full dilution" due to the adoption of SFAS No. 128 as discussed in Note 1.

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, 1998.

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, 1998.

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, 1998.

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, 1998.

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 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 4.7 above).

4.11 Form of 6 1/2% Convertible Junior Subordinated Debentures (included as Exhibit B to 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 First Amendment to Credit Agreement, dated March 15, 1997, among Devon Energy Corporation (Nevada), as Borrower, the Registrant, as Guarantor, 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 (incorporated by reference to Exhibit 10.2 to Registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 1997).

10.3 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)].*

10.4 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).*

10.5 Devon Energy Corporation 1997 Stock Option Plan (incorporated by reference to Exhibit A to Registrant's Proxy Statement for the 1997 Annual Meeting of the Shareholders filed on April 3, 1997).*

10.6 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).*

10.7 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).*

10.8 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).*

10.9 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).*

10.10	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).*
10.11	Severance Agreement between Devon Energy Corporation (Nevada), Registrant and Duke R. Ligon, dated March 26, 1997 (incorporated by reference to Exhibit 10.11 to Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 1997).*
10.12	Employment Agreement between Devon Energy Corporation (Nevada), Registrant and Duke R. Ligon, dated February 7, 1997 (incorporated by reference to Exhibit 10.12 to Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 1997).*
10.13	Supplemental Retirement Income Agreement among Devon Energy Corporation (Nevada), Registrant and John W. Nichols, dated March 26, 1997 (incorporated by reference to Exhibit 10.13 to Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 1997).*
10.14	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).
10.15	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).
10.16	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 (incorporated by reference to Exhibit 21 to Registrant's Form 10-K for the year ended December 31, 1996).
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 of1997. A Current Report on Form 8-K dated January 20, 1998, was filed by the Registrant regarding year-end 1997 reserves, 1997 production and modifications to 1997 forward-looking information. A Current Report on Form 8-K dated January 27, 1998, was filed by the Registrant regarding 1998 forward-looking information.

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 13, 1998 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 13, 1998               By  John W. Nichols
                             John W. Nichols
                             Chairman of the Board and Director


March 13, 1998               By J. Larry Nichols
                             J. Larry Nichols
                             President, Chief Executive Officer
                             and Director


March 13, 1998               By William T. Vaughn
                             William T. Vaughn
                             Vice President - Finance


March 13, 1998               By Danny J. Heatly
                             Danny J. Heatly
                             Controller


March 13, 1998               By H. R. Sanders, Jr.
                             H. R. Sanders, Jr.
                             Director


March 13, 1998               By Luke R. Corbett
                             Luke R. Corbett, Director
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March 13, 1998 By Thomas F. Ferguson Thomas F. Ferguson, Director

March 13, 1998 By David M. Gavrin David M. Gavrin, Director

March 13, 1998 By Michael E. Gellert Michael E. Gellert, Director

March 13, 1998 By Tom J. McDaniel Tom J. McDaniel, Director

March 13, 1998 By Lawrence H. Towell Lawrence H. Towell, Director

INDEX TO EXHIBITS

	Texas, N.A., Bank of Montreal, and First Union National Bank of North Carolina, as Lenders	#

10.2 First Amendment to Credit Agreement dated March 15, 1997, among Devon Energy Corporation (Nevada), as Borrower, the Registrant, as Guarantor, 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 #

10.3	Devon Energy Corporation 1988 Stock Option Plan	#
10.4	Devon Energy Corporation 1993 Stock Option Plan	#
10.5	Devon Energy Corporation 1997 Stock Option Plan	#
10.6	Severance Agreement between Devon Energy Corporation (Nevada), Devon Energy Corporation (Delaware) and Mr. J. Larry Nichols, dated December 3, 1992	#
10.7	Severance Agreement between Devon Energy Corporation (Nevada), Devon Energy Corporation (Delaware) and Mr. J. Michael Lacey, dated December 3, 1992	#
10.8	Severance Agreement between Devon Energy Corporation (Nevada), Devon Energy Corporation (Delaware) and Mr. H. Allen Turner, dated December 3, 1992	#
10.9	Severance Agreement between Devon Energy Corporation (Nevada), Devon Energy Corporation (Delaware) and Mr. Darryl G. Smette, dated December 3, 1992	#
10.10	Severance Agreement between Devon Energy Corporation (Nevada), Devon Energy Corporation (Delaware) and Mr. William T. Vaughn, dated December 3, 1992	#
10.11	Severance Agreement between Devon Energy Corporation (Nevada), Registrant and Duke R. Ligon, dated March 26, 1997	#
10.12	Employment Agreement between Registrant and Duke R. Ligon, dated February 7, 1997	#
10.13	Supplemental Retirement Income Agreement between Devon Energy Corporation (Nevada), Registrant and John W. Nichols, dated March 26, 1997	#
10.14	Sale and Purchase Agreement relating to Registrant's San Juan Basin gas properties	#
10.15	Second Restatement of and Amendment to Sale and Purchase Agreement relating to Registrant's San Juan Basin gas properties	#
10.16	Registration Rights Agreement dated July 3, 1996, by and among the Registrant, Devon Financing Trust and Morgan Stanley & Co. Incorporated	#
11	Computation of earnings per share	99
12	Computation of ratio of earnings to fixed charges	100
21	Subsidiaries of Registrant	#

23.1 Consent of LaRoche Petroleum Consultants, Ltd. 101

23.2 Consent of AMH Group Ltd. 102

23.3 Consent of KPMG Peat Marwick LLP 103 # Incorporated by reference.

DEVON ENERGY CORPORATION Exhibit 11

Computation of Earnings Per Share

	Year Ended December 31, 1997	1996	1995
BASIC EARNINGS PER SHARE			
Net earnings per statement of operations	$75,291,529	34,800,532	14,501,899
Weighted average common shares outstanding	32,215,745	22,159,507	22,073,550
Basic earnings per share	$2.34	1.57	0.66
DILUTED EARNINGS PER SHARE			
Net earnings per statement of operations	$75,291,529	34,800,532	14,501,899
Increase in net earnings from assumed conversion of Trust Convertible Preferred Securities (net of tax effect)	6,025,955	2,997,779	-
Net earnings, as adjusted	$81,317,484	37,798,311	14,501,899
Weighted average common shares outstanding as shown in basic computation above	32,215,745	22,159,507	22,073,550
Add weighted average of additional shares issued from assumed conversion of Trust Convertible Preferred Securities	4,901,507	2,383,793	-
Add fully dilutive effect of outstanding stock options (as determined using the treasury stock method)	408,477	254,352	-
Weighted average common shares outstanding, as adjusted	37,525,729	24,797,625	22,204,171
Diluted earnings per common share	$2.17	1.52	0.65

DEVON ENERGY CORPORATION Exhibit 12

Computation of Ratio of Earnings to Fixed Charges

	Year Ended December 31, 1997	1996	1995
Earnings before income taxes	$121,340,529	59,298,532	25,621,899
Add:			
Interest expense	273,821	5,276,527	7,051,142
Distributions on preferred securities of subsidiary	9,717,502	4,753,125	-
Amortization of costs incurred in connection with the offering of the preferred securities of subsidiary trust	161,113	82,003	-
Estimated interest factor of operating lease payments	376,965	190,726	182,129
Earnings, as adjusted (A)	$131,869,930	69,600,913	32,855,170
Fixed charges:			
Interest costs incurred	273,821	5,276,527	7,051,142
Distributions on preferred securities of subsidiary trust	9,717,502	4,753,125	-
Amortization of costs incurred in connection with the offering of the preferred securities of subsidiary trust	161,113	82,003	-
Estimated interest factor of operating lease payments	376,965	190,726	182,129
Total fixed charges (B)	$10,529,401	10,302,381	7,233,271
Ratio of earnings to fixed charges (A) / (B)	12.52	6.76	4.54

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, 1997, which appears in the December 31, 1997 annual report on Form 10-K of Devon Energy Corporation.

WILLIAM E. LAROCHE
LAROCHE PETROLEUM CONSULTANTS, LTD.

March 10, 1998

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, 1997, which appears in the December 31, 1997 annual report on Form 10-K of Devon Energy Corporation.

ALLEN ASTON
AMH GROUP, LTD.

March 10, 1998

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 January 26, 1998, relating to the consolidated balance sheets of Devon Energy Corporation and subsidiaries as of December 31, 1997, 1996 and 1995 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, 1997 annual report on Form 10- K of Devon Energy Corporation.

KPMG Peat Marwick LLP KPMG Peat Marwick LLP

Oklahoma City, Oklahoma
March 10, 1998

ARTICLE 5

PERIOD TYPE	YEAR
FISCAL YEAR END	DEC 31 1997
PERIOD END	DEC 31 1997
CASH	42064344
SECURITIES	0
RECEIVABLES	47507805
ALLOWANCES	0
INVENTORY	2422822
CURRENT ASSETS	93228894
PP&E	1103320502
DEPRECIATION	365517722
TOTAL ASSETS	846403042
CURRENT LIABILITIES	30812825
BONDS	0
PREFERRED MANDATORY	3231890
PREFERRED	0
COMMON	0
OTHER SE	540344403
TOTAL LIABILITY AND EQUITY	846403042
SALES	305748135
TOTAL REVENUES	313139868
CGS	0
TOTAL COSTS	0
OTHER EXPENSES	83578889
LOSS PROVISION	0
INTEREST EXPENSE	273821
INCOME PRETAX	121340529
INCOME TAX	46049000
INCOME CONTINUING	75291529
DISCONTINUED	0
EXTRAORDINARY	0
CHANGES	0
NET INCOME	75291529
EPS PRIMARY	2.34
EPS DILUTED	2.17

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