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

FORM 10-K

[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(D) OF THE SECURITIES EXCHANGE ACT OF 1934

For the Fiscal Year Ended December 31, 2003

OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the Transition Period from ___________________ to _____________________

Commission File Number 0-13546

APACHE OFFSHORE INVESTMENT PARTNERSHIP

A Delaware General Partnership	IRS Employer No. 41-1464066

One Post Oak Central
2000 Post Oak Boulevard, Suite 100
Houston, Texas 77056-4400

Telephone Number (713) 296-6000

SECURITIES REGISTERED PURSUANT TO SECTION 12(b) OF THE ACT: NONE

SECURITIES REGISTERED PURSUANT TO SECTION 12(g) OF THE ACT:
PARTNERSHIP UNITS

Indicate by check mark whether the Partnership (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 Partnership was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

YES [X] NO [ ]

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of Partnership'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|

Indicate by check whether registrant is an accelerated filer (as defined in Rule 12b-2 of the Act). [ ]

Aggregate market value of the voting and non-voting common equity held by non-affiliates of registrant as of June 30, 2003.................. $13,628,508

DOCUMENTS INCORPORATED BY REFERENCE:

Portions of Apache Corporation's proxy statement relating to its 2004 annual meeting of stockholders have been incorporated by reference into Part III hereof.

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All defined terms under Rule 4-10(a) of Regulation S-X shall have their statutorily-prescribed meanings when used in this report. Quantities of natural gas are expressed in this report in terms of thousand cubic feet (Mcf), million cubic feet (MMcf) or billion cubic feet (Bcf). Oil is quantified in terms of barrels (bbls), thousands of barrels (Mbbls) and millions of barrels (MMbbls). Natural gas is compared to oil in terms of barrels of oil equivalent (boe) or million barrels of oil equivalent (MMboe). Oil and natural gas liquids are compared with natural gas in terms of million cubic feet equivalent (MMcfe) and billion cubic feet equivalent (Bcfe). One barrel of oil is the energy equivalent of six Mcf of natural gas. Daily oil and gas production is expressed in terms of barrels of oil per day (bopd) and thousands of cubic feet of gas per day (Mcfd), respectively. With respect to information relating to the Partnership's working interest in wells or acreage, "net" oil and gas wells or acreage is determined by multiplying gross wells or acreage by the Partnership's working interest therein. Unless otherwise specified, all references to wells and acres are gross.

PART I

ITEM 1. BUSINESS

GENERAL

Apache Offshore Investment Partnership (the Investment Partnership), a Delaware general partnership, was organized in October 1983, with public investors as Investing Partners and Apache Corporation (Apache), a Delaware corporation, as Managing Partner. The operations of the Investment Partnership are conducted by Apache Offshore Petroleum Limited Partnership (the Limited Partnership), a Delaware limited partnership, of which Apache is the sole general partner and the Investment Partnership is the sole limited partner.

The Partnership does not maintain a website, so we do not make electronic access to our reports filed with the SEC available on or through a website. The Partnership will, however, provide paper copies of these filings, free of charge, to anyone so requesting. Any such requests should be made by mail to Apache Offshore Investment Partnership, 2000 Post Oak Blvd., Houston, Texas 77056, Attention: David Higgins, or by telephone at 713-296-6000.

The Investing Partners purchased Units of Partnership Interests (Units) in the Investment Partnership at $150,000 per Unit, with five percent down and the balance in payments as called by the Investment Partnership. As of December 31, 2003, a total of $85,000 had been called for each Unit. In 1989, the Investment Partnership determined that the full $150,000 per Unit was not needed, fixed the total calls at $85,000 per Unit, and released the Investing Partners from liability for future calls. The Investment Partnership invested, and will continue to invest, its entire capital in the Limited Partnership. As used hereafter, the term "Partnership" refers to either the Investment Partnership or the Limited Partnership, as the case may be.

The Partnership's business is participation in oil and gas exploration, development and production activities on federal lease tracts in the Gulf of Mexico, offshore Louisiana and Texas. Except for the Matagorda Island Block 681 and 682 interests, as described below, the Partnership acquired its oil and gas interests through the purchase of 85 percent of the working interests held by Apache as a participant in a venture (the Venture) with Shell Oil Company (Shell) and certain other companies. The Partnership owns working interests ranging from 6.29 percent to 7.08 percent in the Venture's properties.

The Venture acquired substantially all of its oil and gas properties through bidding for leases offered by the federal government. The Venture members relied on Shell's knowledge and expertise in determining bidding strategies for the acquisitions. When Shell was successful in obtaining the properties, it generally billed participating members on a promoted basis (one-third for one-quarter) for the acquisition of exploratory leases and on a straight-up basis for the acquisition of leases defined as drainage tracts. All such billings were proportionately reduced to each member's working interest.

In November 1992, Apache and the Partnership formed a joint venture to acquire Shell's 92.6 percent working interest in Matagorda Island Blocks 681 and 682 pursuant to a jointly-held contractual preferential right to purchase. Apache and the Partnership previously owned working interests in the blocks equal to 1.109 percent and 6.287 percent, respectively, and net revenue interests of .924 percent and 5.239 percent, respectively. To facilitate the acquisition, Apache and the Partnership contributed all of their interests in Matagorda Island Blocks 681 and 682 to a newly formed joint venture, and Apache contributed $64.6 million ($55.6 million net of purchase price adjustments) to the joint venture to finance the acquisition. The Partnership had neither the cash nor additional financing to fund a proportionate share of the acquisition and participated through an increased net revenue interest in the joint venture.

Under the terms of the joint venture agreement, the Partnership's effective net revenue interest in the Matagorda Island Block 681 and 682 properties increased to 13.284 percent as a result of the acquisition, while its working interest was unchanged. The acquisition added approximately 7.5 Bcf of natural gas and 16 Mbbls of oil to the Partnership's reserve base without any incremental expenditures by the Partnership.

Since the Venture is not expected to acquire any additional exploratory acreage, future acquisitions, if any, will be confined to those leases defined as drainage tracts. The current Venture members would pay their proportionate share of acquiring any drainage tracts on a non-promoted basis.

Offshore exploration differs from onshore exploration in that production from a prospect generally will not commence until a sufficient number of productive wells have been drilled to justify the significant costs associated with construction of a production platform. Exploratory wells usually are drilled from mobile platforms until there are sufficient indications of commercial production to justify construction of a permanent production platform.

On an ongoing basis, the Partnership reviews the possible sale of lower value properties prior to incurring associated dismantlement and abandonment costs.

Apache, as Managing Partner, manages the Partnership's operations. Apache uses a portion of its staff and facilities for this purpose and is reimbursed for actual costs paid on behalf of the Partnership, as well as for general, administrative and overhead costs properly allocable to the Partnership.

2003 RESULTS AND BUSINESS DEVELOPMENT

The Partnership reported net income in 2003 of $8.0 million, or $5,598 per Investing Partner Unit including the cumulative effect of a change in accounting principle. Earnings before the cumulative effect of the change in accounting principles totaled $7.7 million, or more than twice the Partnership's 2002 earnings. The change in accounting principle reflects the Partnership's adoption of Statement of Financial Accounting Standard (SFAS) No. 143, Accounting for Asset Retirement Obligations. Natural gas production averaged 3,924 Mcf per day, while oil sales averaged 342 barrels per day. Production added through successful recompletions in 2003 and a full year's production from North Padre Island 969 more than offset declines from natural depletion.

During 2003, the Partnership did not participate in drilling any new wells, but continued to participate in recompletion projects to maintain production and enhance recoverable reserves. During 2003, the Partnership participated in nine recompletions at South Timbalier 295 and one at Ship Shoal 259.

Since inception, the Partnership has acquired an interest in 49 prospects. As of December 31, 2003, 43 of those prospects have been surrendered or sold.

As of December 31, 2003, the Partnership had 52 producing wells on the Partnership's six remaining developed fields. Two of the Partnership's producing wells are dual completions. The Partnership had, at December 31, 2003, estimated proved oil and gas reserves of 9.7 Bcfe, of which 62 percent was natural gas.

MARKETING

Apache, on behalf of the Partnership, seeks and negotiates oil and gas marketing arrangements with various marketers and purchasers. The Partnership's oil and condensate production during 2003 was purchased largely by Chevron Texaco at market prices.

Effective with July 2003 production, the Managing Partner began directly marketing the Partnership's and its own U.S. natural gas production. Most of the Partnership's natural gas production was previously marketed through Cinergy Marketing and Trading, LLC (Cinergy) under a gas sales agreement between the Managing Partner and Cinergy. The Partnership believes that the sales prices it receives for natural gas sales are comparable to prices that would have been received from Cinergy.

In 1998, Apache sold its interest in Producers Energy Marketing LLC (ProEnergy) (a gas marketing company formed by Apache and other natural gas producers) to Cinergy Corp., with ProEnergy being renamed Cinergy Marketing & Trading, LLC (Cinergy). In July 1998, in connection with the sale of its interest, Apache entered into a gas purchase agreement with Cinergy to market most of its U.S. natural gas production for a ten-year period, with an option, after prior notice, to terminate after six years. Apache also sold most of the Partnership's natural gas production to Cinergy under the gas purchase agreement.

See Note (5) "Major Customer and Related Parties Information" to the Partnership's financial statements under Item 8. Because the Partnership's oil and gas products are commodities and the prices and terms of its sales reflect those of the market, the Partnership does not believe that the loss of any customer would have a material adverse affect on the Partnership's business or results of operations. The Partnership is not in a position to predict future oil and gas prices.

RISK FACTORS RELATED TO THE PARTNERSHIP'S BUSINESS AND OPERATIONS

VOLATILE PRICES CAN MATERIALLY AFFECT THE PARTNERSHIP

The Partnership continually analyzes forecasts and updates its estimates of energy prices for its internal use in planning, budgeting, and estimating and valuing reserves. The Partnership's future financial condition and results of operations will depend upon the prices received for the Partnership's oil and natural gas production and the costs of acquiring, finding, developing and producing reserves. Prices for oil and natural gas are subject to fluctuations in response to relatively minor changes in supply, market uncertainty and a variety of additional factors that are beyond the control of the Partnership. These factors include worldwide political instability (especially in the Middle East and other oil-producing regions), the foreign supply of oil and gas, the price of foreign imports, the level of drilling activity, the level of consumer product demand, government regulations and taxes, the price and availability of alternative fuels and the overall economic environment. A substantial or extended decline in oil and gas prices would have a material adverse effect on the Partnership's financial position, results of operations, quantities of oil and gas that may be economically produced, and access to capital. Oil and natural gas prices have historically been and are likely to continue to be volatile. This volatility makes it difficult to estimate with precision the value of producing properties in acquisitions and to budget and project the return on exploration and development projects involving the Partnership's oil and gas properties.

UNCERTAINTY IN CALCULATING RESERVES; RATES OF PRODUCTION; DEVELOPMENT EXPENDITURES; CASH FLOWS

There are numerous uncertainties inherent in estimating quantities of oil and natural gas reserves of any category and in projecting future rates of production and timing of development expenditures, which underlie the reserve estimates, including many factors beyond the Partnership's control. Reserve data represent only estimates. In addition, the estimates of future net cash flows from the Partnership's proved reserves and their present value are based upon various assumptions about future production levels, prices and costs that may prove to be incorrect over time. Any significant variance from the assumptions could result in the actual quantity of the Partnership's reserves and future net cash flows from them being materially different from the estimates. In addition, the Partnership's estimated reserves may be subject to downward or upward revision based upon production history, results of future exploration and development, prevailing oil and gas prices, operating and development costs and other factors.

COSTS INCURRED RELATED TO ENVIRONMENTAL MATTERS

The Partnership, as an owner or lessee of interests in oil and gas properties, is subject to various federal, state and local laws and regulations relating to the discharge of materials into, and protection of, the environment. These laws and regulations may, among other things, impose liability on the lessee under an oil and gas lease for the cost of pollution clean-up resulting from operations, subject the lessee to liability for pollution damages and require suspension or cessation of operations in affected areas.

The Partnership has made and will continue to make expenditures in its efforts to comply with these requirements. These costs are inextricably connected to normal operating expenses such that the Partnership is unable to separate the expenses related to environmental matters; however, the Partnership does not believe such expenditures are material to its financial position or results of operations. The Partnership had not incurred any material environmental remediation costs in any of the periods presented and is not aware of any future environmental remediation matters that would be material to its financial position or results of operations.

The Partnership does not believe that compliance with federal, state or local provisions regulating the discharge of materials into the environment, or otherwise relating to the protection of the environment, will have a material adverse effect upon the capital expenditures, earnings and the competitive position of the Partnership, but there is no assurance that changes in or additions to laws or regulations regarding the protection of the environment will not have such an impact.

INSURANCE DOES NOT COVER ALL RISKS

Exploration for and production of oil and natural gas can be hazardous, involving unforeseen occurrences such as blowouts, cratering, fires and loss of well control, which can result in damage to or destruction of wells or production facilities, injury to persons, loss of life, or damage to property or the environment. Apache, as managing partner, maintains insurance against certain losses or liabilities arising from the Partnership's operations in accordance with customary industry practices and in amounts that management believes to be prudent; however, insurance is not available to the Partnership's against all operational risks.

COMPETITION WITH OTHER COMPANIES COULD HARM THE PARTNERSHIP

The Partnership is a very minor factor in the oil and gas industry in the Gulf of Mexico area and faces strong competition from much larger producers for the marketing of its oil and gas. The Partnership's ability to compete for purchasers and favorable marketing terms will depend on the general demand for oil and gas from Gulf of Mexico producers. More particularly, it will depend largely on the efforts of Apache to find the best markets for the sale of the Partnership's oil and gas production.

INVESTORS IN THE PARTNERSHIP'S SECURITIES MAY ENCOUNTER DIFFICULTIES IN OBTAINING, OR MAY BE UNABLE TO OBTAIN, RECOVERIES FROM ARTHUR ANDERSEN WITH RESPECT TO ITS AUDITS OF OUR FINANCIAL STATEMENTS

On March 14, 2002, the Partnership's previous independent public accountant, Arthur Andersen LLP, was indicted on federal obstruction of justice charges arising from the federal government's investigation of Enron Corp. On June 15, 2002, a jury returned with a guilty verdict against Arthur Andersen following a trial. We are required to file with the SEC periodic financial statements audited or reviewed by an independent public accountant. On March 29, 2002, the General Partner decided not to engage Arthur Andersen as the Partnership's independent auditors, and engaged Ernst & Young LLP to serve as our new independent auditors for 2002. Ernst & Young also served as the Partnership's independent auditors in 2003. However, included in this annual report on Form 10-K are financial data and other information for 2001 that were audited by Arthur Andersen. Investors in the Partnership's securities may encounter difficulties in obtaining, or be unable to obtain, from Arthur Andersen with respect to its audits of our financial statements relief that may be available to investors under the federal securities laws against auditing firms.

ITEM 2. PROPERTIES

ACREAGE

Acreage is held by the Partnership pursuant to the terms of various leases. The Partnership does not anticipate any difficulty in retaining any of its desirable leases. A summary of the Partnership's gross and net acreage as of December 31, 2003, is set forth below:

		DEVELOPED ACREAGE	
LEASE BLOCK	STATE	GROSS ACRES	NET ACRES
Ship Shoal 258, 259	LA	10,141	638
South Timbalier 276, 295, 296	LA	15,000	1,063
North Padre Island 969, 976	TX	10,080	714
Matagorda Island 681, 682, 683	TX	15,840	742
South Pass 83	LA	5,000	339
Ship Shoal 201, 202	LA	10,000	-
		66,061	3,496

At December 31, 2003, the Partnership did not have an interest in any undeveloped acreage.

PRODUCTIVE OIL AND GAS WELLS

The number of productive oil and gas wells in which the Partnership had an interest as of December 31, 2003, is set forth below:

		GAS		OIL	
LEASE BLOCK	STATE	GROSS	NET	GROSS	NET
Ship Shoal 258, 259	LA	4	.25	-	-
South Timbalier 276, 295, 296	LA	1	.07	32	2.27
North Padre Island 969, 976	TX	5	.35	-	-
Matagorda Island 681, 682, 683	TX	7	.44	-	-
South Pass 83	LA	1	.07	-	-
Ship Shoal 201, 202	LA	1	-	1	-
		19	1.18	33	2.27

NET WELLS DRILLED

The following table shows the results of the oil and gas wells drilled and tested for each of the last three fiscal years:

	NET EXPLORATORY			NET DEVELOPMENT		
YEAR	PRODUCTIVE	DRY	TOTAL	PRODUCTIVE	DRY	TOTAL
2003	-	-	-	-	-	-
2002	-	-	-	.35	.07	.42
2001	-	-	-	.28	-	.28

PRODUCTION AND PRICING DATA

The following table describes, for each of the last three fiscal years, oil, natural gas liquids (NGLs) and gas production for the Partnership, average production costs (including gathering and transportation expense) and average sales prices.

	PRODUCTION			AVERAGE	AVERAGE SALES PRICES		
YEAR ENDED DECEMBER 31,	OIL (MBBLS)	GAS (MMCF)	NGLS (MBBLS)	PRODUCTION COST PER MCFE	OIL (PER BBL)	GAS (PER MCF)	NGLS (PER BBL)
2003	125	1,432	6	$ .42	$ 30.73	$ 5.56	$ 23.92
2002	110	1,224	-	.44	25.03	3.36	-
2001	112	1,705	-	.33	25.00	4.51	-

See the Supplemental Oil and Gas Disclosures under Item 8 for estimated proved oil and gas reserves quantities.

ESTIMATED PROVED RESERVES AND FUTURE NET CASH FLOWS

As of December 31, 2003, the Partnership had total estimated proved reserves of 618,000 barrels of crude oil, condensate and NGLs and 6 Bcf of natural gas. Combined, these total estimated proved reserves are equivalent to 9.7 Bcf of gas. Estimated proved developed reserves comprise 99 percent of the Partnership's total estimated proved reserves on a Bcfe basis.

The Partnership's estimates of proved reserves and proved developed reserves at December 31, 2003, 2002 and 2001, changes in proved reserves during the last three years, and estimates of future net cash flows and discounted future net cash flows from proved reserves are contained in the Supplemental Oil and Gas Disclosures (Unaudited), in the 2003 Consolidated Financial Statements under Item 8 of this Form 10-K.

Proved oil and gas reserves are the estimated quantities of natural gas, crude oil, condensate and NGLs that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Reserves are considered proved if economical producibility is supported by either actual production or conclusive formation tests. Reserves that can be produced economically through application of improved recovery techniques are included in the "proved" classification when successful testing by a pilot project or the operation of an installed program in the reservoir provides support for the engineering analysis on which the project or program is based. Proved developed oil and gas reserves can be expected to be recovered through existing wells with existing equipment and operating methods.

The volumes of reserves are estimates which, by their nature, are subject to revision. The estimates are made using available geological and reservoir data, as well as production performance data. These estimates are reviewed annually and revised, either upward or downward, as warranted by additional performance data.

The Partnership's estimate of proved oil and gas reserves are prepared by Ryder Scott Company, L.P. Petroleum Consultants, independent petroleum engineers, utilizing oil and gas price data and cost estimates provided by Apache as Managing Partner.

ITEM 3. LEGAL PROCEEDINGS

There are no material legal proceedings pending to which the Partnership is a party or to which the Partnership's interests are subject.

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

There were no matters submitted to a vote of security holders during the fourth quarter of 2003.

PART II

ITEM 5. MARKET FOR THE PARTNERSHIP'S SECURITIES AND RELATED SECURITY HOLDER MATTERS

As of December 31, 2003, there were 1,060.7 of the Partnership's Units outstanding held by 879 investors of record. The Partnership has no other class of security outstanding or authorized. The Units are not traded on any security market. Cash distributions to Investing Partners totaled approximately $4.8 million, or $4,500 per Unit, during 2003 and approximately $1.1 million, or $1,000 per Unit, during 2002.

As discussed in Item 7, an amendment to the Partnership Agreement in February 1994 created a right of presentment under which all Investing Partners have a limited and voluntary right to offer their Units to the Partnership twice each year to be purchased for cash.

ITEM 6. SELECTED FINANCIAL DATA

The following selected financial data for the five years ended December 31, 2003, should be read in conjunction with the Partnership's financial statements and related notes included under Item 8 below of this Form 10-K. The Partnership's financial statements for the years 1999 through 2001 were audited by Arthur Andersen LLP, independent public accountants. For a discussion of the risks relating to Arthur Andersen's audit of the Partnership's financial statements, please see "Factors That May Affect Future Results - Risks Relating to Arthur Andersen LLP".

	AS OF OR FOR THE YEAR ENDED DECEMBER 31,				
	2003	2002	2001	2000	1999
	(In thousands, except per Unit amounts)				
Total assets	$ 11,674	$ 9,834	$ 9,413	$ 8,715	$ 8,722
Partners' capital	$ 10,475	$ 9,610	$ 8,369	$ 7,728	$ 7,755
Oil and gas sales	$ 11,951	$ 6,868	$ 10,495	$ 12,641	$ 8,796
Net income	$ 8,037	$ 3,524	$ 7,264	$ 8,497	$ 4,351
Net income allocated to:					
Managing Partner	$ 2,037	$ 1,036	$ 1,731	$ 2,102	$ 1,269
Investing Partners	6,000	2,488	5,533	6,395	3,082
	$ 8,037	$ 3,524	$ 7,264	$ 8,497	$ 4,351
Net income per Investing Partner Unit	$ 5,598	$ 2,259	$ 4,922	$ 5,654	$ 2,707
Cash distributions per Investing Partner Unit	$ 4,500	$ 1,000	$ 4,000	$ 5,750	$ 3,500

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

OVERVIEW

The Partnership's business is participation in oil and gas exploration, development and production activities on federal lease tracts in the Gulf of Mexico, offshore Louisiana and Texas. The Partnership is a very minor factor in the oil and gas industry and faces strong competition in all aspects of its business. With a relatively small amount of capital invested in the Partnership and management's decision to avoid incurring debt, the Partnership has not engaged in acquisition or exploration activities in recent years. The Partnership has not carried any debt since January 1997. The limited amount of capital and the Partnership's modest reserve base have contributed to the Partnership focusing on production activities and developing existing leases.

As with other independent energy companies, the Partnership derives its revenue from the production and sale of crude oil, natural gas and natural gas liquids. The Partnership sells its production at market prices and has not used derivative financial instruments or otherwise engaged in hedging activities. With tight supplies of natural gas in the United States and political concerns impacting world oil markets, the Partnership benefited from high oil and gas prices throughout 2003. Commodity prices, however, have historically been volatile. This volatility has caused the Partnership's revenues and resulting cash flow from operating activities to fluctuate widely over the years.

The Partnership participates in development drilling and recompletion activities as recommended by outside operators and the Partnership's Managing Partner. These activities have helped stem the decline in the Partnership's production in recent years and even contributed to an increase in production in 2003. Generally, the Partnership has used remaining available cash to fund distributions to its partners.

The Partnership's net income and net income per Investing Partner Unit increased in 2003 on higher oil and gas production and prices. Daily oil and gas volumes increased 13 percent and 17 percent, respectively, from a year ago as a result of successful recompletions in 2003 and a full year's production from North Padre Island 969. Distributions per Investing Partner Unit in 2003 also increased as a result of the higher production and gas prices. There were two distributions made to the Investing Partners in 2003 for a total per unit distribution of $4,500.

CRITICAL ACCOUNTING POLICIES

The discussion and analysis of the Partnership's financial condition and results of operations are based upon the consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of these financial statements requires the Partnership to make estimates and assumptions that affect the reported amount of assets, liabilities, revenues and expenses. Certain accounting policies involve judgments and uncertainties to such an extent that there is a reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. The Partnership bases its estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances. Actual results may differ from the estimates and assumptions used in preparation of the financial statements. The following details the more significant accounting policies, estimates and judgments. Additional accounting policies and estimates made by management are discussed in Note 2 of Item 8 of this Form 10-K.

Full Cost Method of Accounting for Oil and Gas Operations

The accounting for the Partnership's business is subject to special accounting rules that are unique to the oil and gas industry. There are two allowable methods of accounting for oil and gas business activities: the successful efforts method and the full cost method. There are several significant differences between these methods. Under the successful efforts method, costs such as geological and geophysical (G&G), exploratory dry holes and delay rentals are expensed as incurred, where under the full-cost method these types of charges would be capitalized to oil and gas properties. In the measurement of impairment of oil and gas properties, the successful efforts method of accounting follows the guidance provided in Statement of Financial Accounting Standards (SFAS) No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets", where the first measurement for impairment is to compare the net book value of the related asset to its undiscounted future cash flows using commodity prices consistent with management expectations. Under the full-cost method the net book value (full-cost pool) is compared to the future net cash flows discounted at 10% using commodity prices in effect at the end of the reporting period.

The Partnership has elected to use the full cost method to account for its investment in oil and gas properties. Under this method, the Partnership capitalizes all acquisition, exploration and development costs for the purpose of finding oil and gas reserves. Although some of these costs will ultimately result in no additional reserves, it expects the benefits of successful wells to more than offset the costs of any unsuccessful ones. As a result, the Partnership believes that the full cost method of accounting better reflects the true economics of exploring for and developing oil and gas reserves. The Partnership's financial position and results of operations would have been significantly different had it used the successful efforts method of accounting for oil and gas investments.

The Partnership has taken note of a July 2003 inquiry to the Financial Accounting Standards Board (FASB) regarding whether or not contract-based oil and gas mineral rights held by lease or contract ("mineral rights") should be recorded or disclosed as intangible assets. The inquiry presents a view that these mineral rights are intangible assets as defined in SFAS No. 141, "Business Combinations," and, therefore, should be classified separately on the balance sheet as intangible assets. SFAS No. 141, and SFAS No. 142, "Goodwill and Other Intangible Assets," became effective for transactions subsequent to June 30, 2001 with the disclosure requirements of SFAS No. 142 required as of January 1, 2002. SFAS No. 141 requires that all business combinations initiated after June 30, 2001 be accounted for using the purchase method and that intangible assets be disaggregated and reported separately from goodwill. SFAS No. 142 established new accounting guidelines for both finite lived intangible assets and indefinite lived intangible assets. Under the statement, intangible assets should be separately reported on the face of the balance sheet and accompanied by disclosure in the notes to financial statements. SFAS No. 142 scopes out accounting utilized by the oil and gas industry as prescribed by SFAS No. 19, and is silent about whether or not its disclosure provisions apply to oil and gas companies. The Partnership does not believe that SFAS No. 141 or 142 change the classification of oil and gas mineral rights and the Partnership continues to classify these assets as part of oil and gas properties. Also, the Partnership has not participated in any business combinations or major asset acquisition since the June 30, 2001 effective date of SFAS No. 141 and SFAS No. 142. The Emerging Issues Task Force (EITF) has added the treatment of oil and gas mineral rights to an upcoming agenda, which may result in a change in how the Partnership classifies these assets.

Reserve Estimates

The Partnership's estimate of proved reserves are based on the quantities of oil and gas which geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under existing economic and operating conditions. The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation, and judgment. For example, engineers must estimate the amount and timing of future operating costs, severance taxes, development costs, and workover costs, all of which may in fact vary considerably from actual results. In addition, as prices and cost levels change from year to year, the estimate of proved reserves also change. Any significant variance in these assumptions could materially affect the estimated quantity and value of the Partnership's reserves.

Despite the inherent imprecision in these engineering estimates, the Partnership's reserves have a significant impact on its financial statements. For example, the quantity of reserves could significantly impact the Partnership's DD&A expense. The Partnership's oil and gas properties are also subject to a "ceiling" limitation based in part on the quantity of our proved reserves. These reserves are the basis for our supplemental oil and gas disclosures.

The Partnership's estimate of proved oil and gas reserves are prepared by Ryder Scott Company, L.P. Petroleum Consultants, independent petroleum engineers, utilizing oil and gas price data and cost estimates provided by Apache as Managing Partner.

Asset Retirement Obligation

The Partnership has obligations to remove tangible equipment and restore land or seabed at the end of oil and gas production operations. These obligations may be significant in light of the Partnership's limited operations and estimate of remaining reserves. The Partnership's removal and restoration obligations are primarily associated with plugging and abandoning wells and removing and disposing of offshore oil and gas platforms. Estimating the future restoration and removal costs is difficult and requires management to make estimates and judgments because most of the removal obligations are many years in the future and contracts and regulations often have vague descriptions of what constitutes removal. Asset removal technologies and costs are constantly changing, as are regulatory, political, environmental, safety and public relations considerations. Prior to 2003, under the full-cost method of accounting, as described in the preceding critical accounting policy sections, the estimated undiscounted costs of the

abandonment obligations, net of the value of salvage, were currently included as a component of the Partnership's depletion base and expensed over the production life of the oil and gas properties.

In 2001, the FASB issued SFAS No. 143 "Accounting for Asset Retirement Obligations." The Partnership adopted this statement effective January 1, 2003, as discussed in Note 8 of this Form 10-K. SFAS No. 143 significantly changed the method of accruing for costs an entity is legally obligated to incur related to the retirement of fixed assets ("asset retirement obligations" or "ARO"). Primarily, the new statement requires the Partnership to record a separate liability for the discounted present value of the Partnership's asset retirement obligations, with an offsetting increase to the related oil and gas properties on the balance sheet.

Inherent in the present value calculation are numerous assumptions and judgments including the ultimate settlement amounts, inflation factors, credit adjusted discount rates, timing of settlement, and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the present value of the existing ARO liability, a corresponding adjustment is made to the oil and gas property balance. In addition, increases in the discounted ARO liability resulting from the passage of time will be reflected as accretion expense in the statement of consolidated income.

SFAS No. 143 requires a cumulative adjustment to reflect the impact of implementing the statement had the rule been in effect since inception. The Partnership, therefore, calculated the cumulative accretion expense on the ARO liability and the cumulative depletion expense on the corresponding property balance. The sum of these cumulative expenses was compared to the depletion expense originally recorded. Because the historically recorded depletion expense was higher than the cumulative expense calculated under SFAS No. 143, the difference resulted in a gain which the Partnership recorded as cumulative effect of change in accounting principle on January 1, 2003.

Upon implementation, the Partnership also had to determine if the statement required us to recalculate our historical full-cost ceiling tests (see Note 1 of this Form 10-K). The Partnership chose not to re-calculate its historical full-cost ceiling tests even though its historical oil and gas property balances would have been higher had we applied the statement from inception. We believe this approach is appropriate because SFAS No. 143 is silent on this issue and was not effective during the prior impairment test periods. Had a recalculation of the historical full-cost ceiling test resulted in impairment, the charge would have reduced the gain recorded upon adoption.

Going forward, the Partnership's depletion expense will be reduced since it will deplete a discounted ARO rather than the undiscounted value previously depleted. The lower depletion expense under SFAS No. 143 is offset, however, by higher accretion expense, which reflects increases in the discounted asset retirement obligation over time.

Also, the Partnership had to determine how to incorporate the asset retirement obligations into the quarterly calculation of its full-cost ceiling tests (see Note 1 Form 10-K). SFAS No. 143 is silent with respect to this issue and, although there are various views, the Partnership elected to continue including the undiscounted ARO as part of future development costs, essentially reducing the present value of its future net revenues and full-cost ceiling limit. To compare the property balance, which included the ARO component, to the full-cost ceiling limit, which has been reduced by a similar abandonment cost, we netted the ARO liability against the property balance. The Partnership believes its view is appropriate since there must be a comparable basis between the net book value of the properties and the full-cost ceiling limitation. Another widely contemplated view is to exclude the ARO from future development costs when calculating the full-cost ceiling limitation and not reduce the carrying amount of capitalized costs by the related liability. This approach would result in a higher full-cost ceiling limitation and a higher net oil and gas property balance.

RESULTS OF OPERATIONS

NET INCOME AND REVENUE

The Partnership reported net income of $8.0 million for 2003, more than double the net income reported in 2002 on the strength of higher prices and production. Net income per Investing Partner Unit increased in 2003 to $5,598, up from $2,259 in 2002. The Partnership reported earnings of $3.5 million in 2002 versus $7.3 million in 2001. Net income fell in 2002 on lower gas prices and a dip in gas production resulting from natural depletion and the impact of shutting-in production from North Padre Island 969 for nine months in 2002.

Total revenues increased to $12 million in 2003 with higher prices and production. The Partnership's total revenue in 2002 of $7 million was down one-third from 2001 on lower gas prices and production. Interest income earned by the Partnership on short-term cash investments in 2003 increased from 2002 as a result of higher average investment balances in 2003. Interest income in 2002 had declined from $75,000 in 2001 on lower interest rates and average investment balances.

The Partnership's oil and gas production volume and price information is summarized in the following table:

	FOR THE YEAR ENDED DECEMBER 31,		
	2003	2002	2001
Gas volumes - Mcf per day	3,924	3,353	4,672
Average gas price - per Mcf	$ 5.56	$ 3.36	$ 4.51
Oil volumes - barrels per day	342	302	307
Average oil price - per barrel	$ 30.73	$ 25.03	$ 25.00
NGL volumes - barrels per day	16	-	-
Average NGL price - per barrel	$ 23.92	-	-

Declines in oil and gas production can be expected in future years as a result of normal depletion. Given the small number of producing wells owned by the Partnership, and the fact that offshore wells tend to decline at a faster rate than onshore wells, the Partnership's future production will be subject to more volatility than those companies with greater reserves and longer-lived properties. It is not anticipated that the Partnership will acquire any additional exploratory leases or that significant exploratory drilling will take place on leases in which the Partnership currently holds interests.

NATURAL GAS SALES

Natural gas sales for 2003 totaled $8 million, up 94% from 2002 on higher prices and production. The Partnership's average realized natural gas price for 2003 improved 65% from 2002. The $2.20 per Mcf increase in gas price from a year ago boosted sales by approximately $2.7 million. Daily gas production for 2003 increased 17 percent from 2002, increasing sales by $1.2 million. Production added through recompletions at South Timbalier 295 and Ship Shoal 259 in 2003 more than offset natural depletion for the year. Also, production at North Padre Island 969 was shut-in for the first nine months of 2002 for a dispute with a pipeline company on increased fees charged for the transportation of natural gas. The North Padre Island 969 wells returned to production in late September 2002 after the Federal Energy Regulatory Commission (FERC) issued a ruling which established an unbundled gathering rate of approximately two cents per Mcf on the North Padre Island system as opposed to the 12 cents per Mcf rate demanded by the pipeline.

Effective with July 2003 production, the Managing Partner began directly marketing the Partnership's and its own U.S. natural gas production. Most of the Partnership's natural gas production was previously marketed through Cinergy Marketing and Trading, LLC (Cinergy) under a gas sales agreement between the Managing Partner and Cinergy. The Partnership believes that the prices it receives for natural gas are comparable to the prices it would have received from Cinergy. During the fourth quarter of 2003, the Partnership began processing a portion of its natural gas production through on-shore plants operated by third parties.

The Partnership's natural gas sales for 2002 totaled $4.1 million, down 47 percent from 2001 on lower gas prices and production. While natural gas prices improved during the fourth quarter of 2002, a $1.15 per Mcf drop in the Partnership's average realized price from 2001 negatively impacted sales by $2 million. Natural gas production declined by 28 percent from 2001, falling to 3,353 Mcf per day in 2002. The 1,319 Mcf per day decline in volume primarily reflected natural depletion. The Partnership's North Padre Island 969 production being shut-in for nine months in 2002 for a dispute with a pipeline company reduced 2002 sales by 426 Mcf per day, while Hurricane Isidore and Lili reduced 2002 sales by 58 Mcf per day. The North Padre Island 969 wells returned to production in late September 2002 after the FERC issued its ruling on the systems transportation rates. The completion of five successful development wells at South Timbalier 295 during 2002 largely offset production declines in the field.

CRUDE OIL SALES

During 2003, the Partnership's crude oil sales increased 39 percent from 2002 to $3.8 million. A $5.70 per barrel, or 23 percent, increase in the Partnership's average realized oil price in 2003 increased oil revenues by $.6 million from 2002. Oil production increased 13 percent from 2002 as a result of recompletions at South Timbalier 295.

The Partnership's crude oil sales for 2002 totaled $2.8 million, even with 2001. A slight improvement in average realized oil prices in 2002 was offset by a two percent decline in production from 2001. Weather-related downtime for hurricanes in 2002 drove the five barrel per day decline in production from the prior year. Production added through drilling at South Timbalier 295 during 2002 offset natural depletion for the year.

OTHER REVENUES

The Partnership recognized insurance recoveries in 2003 and 2002 totaling $14,567 and $99,300, respectively, for the amount of proceeds recoupable under business interruption insurance policies. The amount reflects recoveries, after applicable deductibles, for the Partnership's share of lost oil and gas production resulting from hurricanes in 2002.

OPERATING EXPENSES

The Partnership's depreciation, depletion and amortization (DD&A) rate, expressed as a percentage of oil and gas sales, decreased to 24 percent in 2003. The decrease in DD&A rate as a percentage of sales reflected higher oil and gas prices in 2003. The Partnership's depreciation, depletion and amortization (DD&A) rate, expressed as a percentage of oil and gas sales, increased to 32 percent in 2002 from 19 percent in 2001 as a result of higher finding cost and lower oil and gas prices in 2002. On an equivalent Mcf basis, the Partnership's DD&A rate increased in both 2003 and 2002 due to higher finding costs in those years.

Lease operating expense in 2003 increased approximately $87,000 from a year ago primarily as result of higher workover and maintenance costs and higher cost at the North Padre Island 969 compared to 2002. Operations and costs at North Padre Island 969 were sustained at a reduced level in 2002 while shut-in during the dispute between the producers and a pipeline company as noted under the discussion of natural gas sales. Administrative expense declined slightly from last year, dropping to $405,000.

Lease operating expense in 2002 increased approximately $96,000 from 2001 primarily as a result of higher repair and maintenance cost on platforms and compressors. Administrative expense declined seven percent from 2001, dropping to $447,000.

The Partnership sells oil and natural gas under two types of transactions, both of which include a transportation charge. One is a netback arrangement, under which the Partnership sells oil or natural gas at the wellhead and collects a price, net of transportation incurred by the purchaser. Under the other arrangement, the Partnership sells oil or natural gas at a specific delivery point, pays transportation to a carrier and receives from the purchaser a price with no transportation deduction.

During 2002, the Partnership adopted Emerging Issues Task Force Issue 00-10, "Accounting for Shipping and Handling Fees and Costs". Prior to adoption, amounts paid to third parties for transportation had been reported as a reduction of revenue instead of an operating expense. For comparative purposes, previously reported transportation costs paid to third parties were reclassified as corresponding increases to oil and gas production revenues and operating expenses with no impact on net income. The increase in transportation cost paid to third parties in 2003 reflected higher sales volumes and a modest increase in transportation rates at North Padre Island 969. The decline in expense in 2002 compared to 2001 reflected lower sales volumes in 2002.

CASH FLOW, LIQUIDITY AND CAPITAL RESOURCES

CAPITAL COMMITMENTS

The Partnership's primary needs for cash are for operating expenses, drilling and recompletion expenditures, future dismantlement and abandonment costs, distributions to Investing Partners, and the purchase of Units offered by Investing Partners under the right of presentment. The Partnership had no outstanding debt or lease commitments at December 31, 2003. The Partnership did not have any contractual obligations as of December 31, 2003, other than the liability for dismantlement and abandonment costs of its oil and gas properties. The Partnership has recorded a separate liability for the fair value of this asset retirement obligation as discussed under the discussion of critical accounting policies noted above.

During 2003, the Partnership's oil and gas property additions, exclusive of ARO-related costs, totaled $1.6 million. These additions primarily related to the Partnership's participation in nine recompletions at South Timbalier 295 and one recompletion at Ship Shoal 259. The Partnership did not participate in drilling any new wells during 2003. Capital expenditures during 2002 totaled $3.2 million as the Partnership participated in drilling six development wells at South Timbalier 295 and Matagorda 681/682. Capital expenditures during 2001 totaled $3 million as the Partnership participated in drilling four development wells at South Timbalier 295 and recompletions at Matagorda Island 681/682 and South Timbalier 295.

As noted above, the Partnership accrues and funds expenditures for future dismantlement and abandonment costs associated with its oil and gas properties. These expenditures will be funded by future cash flows from operations and cash held by the Partnership. At December 31, 2003, the Partnership held $.8 million in short-term cash investments to fund future dismantlement and abandonment costs, approximately the net present value of the Partnership's ARO liability at year-end. These funds are not legally restricted to funding ARO-related cost. During 2003, the Partnership plugged and abandoned the remaining wellbore in the East Cameron 60 field, and removed the platform from the site. The field had not produced since 2001. On an ongoing basis, the Partnership reviews the possible sale of lower value properties prior to incurring associated dismantlement and abandonment costs.

Based on preliminary information provided by the operators of the properties in which the Partnership owns interests, the Partnership anticipates capital expenditures will total approximately $.6 million in 2004 directed primarily toward recompletion projects. Such estimates may change based on realized oil and gas prices, drilling results, rates charged by drilling contractors or changes by the operator to the development plan.

During 2003, the Partnership paid distributions to Investing Partners totaling approximately $4.8 million or $4,500 per Unit; more than four times the 2002 distributions as a result of higher oil and gas prices and production in 2003. The per Unit distribution in 2002 declined 75 percent from 2001 due to the decline in the Partnership's revenues in 2002. The amount of future distributions will be dependent on actual and expected production levels, realized and expected oil and gas prices, expected drilling and recompletion expenditures and prudent cash reserves for future dismantlement and abandonment costs that will be incurred after the Partnership's reserves are depleted.

In February 1994, an amendment to the Partnership Agreement created a right of presentment under which all Investing Partners have a limited and voluntary right to offer their Units to the Partnership twice each year to be purchased for cash. In 2003, the first right of presentment offer of $12,047 per Unit, plus interest to the date of payment, was made to Investing Partners based on a December 31, 2002 valuation date. The second right of presentment offer of $9,512 per Unit, plus interest to the date of payment, was made to the Investing Partners based on a valuation date of June 30, 2003. As a result, the Partnership acquired 24.2 Units for a total of $295,734 in cash. In 2002 and 2001, Investing Partners were paid $213,006 and $195,221, respectively, for a total of 43.6 Units.

There will be two rights of presentment in 2004, but the Partnership is not in a position to predict how many Units will be presented for repurchase and cannot, at this time, determine if the Partnership will have sufficient funds available to repurchase Units. The Amended Partnership Agreement contains limitations on the number of Units that the Partnership can repurchase, including an annual limit on repurchases of 10 percent of outstanding Units. The Partnership has no obligation to repurchase any Units presented to the extent that it determines that it has insufficient funds for such repurchases.

CAPITAL RESOURCES AND LIQUIDITY

The Partnership's primary capital resource is net cash provided by operating activities, which totaled $10.2 million for 2003. Net cash provided by operating activities in 2003 increased $5.2 million, or 106 percent, from a year ago resulting from increase in oil and gas production and prices. Net cash provided by operating activities in 2002 declined 52 percent from 2001 on declines in oil and gas production and gas prices.

The Partnership's future financial condition, results of operations and cash from operating activities will largely depend upon prices received for its oil and natural gas production. A substantial portion of the Partnership's production is sold under market-sensitive contracts. Prices for oil and natural gas are subject to fluctuations in response to changes in supply, market uncertainty and a variety of factors beyond the Partnership's control. These factors include worldwide

political instability (especially in the Middle East), the foreign supply of oil and natural gas, the price of foreign imports, the level of consumer demand, and the price and availability of alternative fuels. With natural gas accounting for 65 percent of the Partnership's 2003 production and 62 percent of total proved reserves, on an energy equivalent basis, the Partnership is affected more by fluctuations in natural gas prices than in oil prices.

The Partnership's oil and gas reserves and production will also significantly impact future results of operations and cash from operating activities. The Partnership's production is subject to fluctuations in response to remaining quantities of oil and gas reserves, weather, pipeline capacity, consumer demand, mechanical performance and workover, recompletion and drilling activities. Declines in oil and gas production can be expected in future years as a result of normal depletion and the Partnership not participating in acquisition or exploration activities. Based on production estimates from independent engineers and current market conditions, the Partnership expects it will be able to meet its liquidity needs for routine operations in the foreseeable future. The Partnership's oil and gas production on an equivalent Mcf basis is projected to decline by approximately 16 percent in each of the next two years. While the rate of decline will not be as significant in following years, the Partnership's production will generally decline each year thereafter. The Partnership will reduce capital expenditures and distributions to partners as cash from operating activities decline.

In the event that future short-term operating cash requirements are greater than the Partnership's financial resources, the Partnership may seek short-term, interest-bearing advances from the Managing Partner as needed. The Managing Partner, however, is not obligated to make loans to the Partnership.

OFF-BALANCE SHEET ARRANGEMENTS

The Partnership does not currently utilize any off-balance sheet arrangements with unconsolidated entities to enhance liquidity and capital resource positions, or any other purpose. Any future transactions involving off-balance sheet arrangements will be fully scrutinized by the Managing Partner and disclosed by the Partnership.

ITEM 7A. MARKET RISK

COMMODITY RISK

The Partnership's major market risk exposure is in the pricing applicable to its oil and gas production. Realized pricing is primarily driven by the prevailing worldwide price for crude oil and spot prices applicable to its natural gas production. Prices received for oil and gas production have been and remain volatile and unpredictable. During 2003, monthly oil price realizations ranged from a low of $27.38 per barrel to a high of $34.62 per barrel. Gas price realizations ranged from a monthly low of $4.59 per Mcf to a monthly high of $9.13 per Mcf during the same period. While remaining strong compared to historical levels, gas prices trended downward during most of 2003. Based on the Partnership's average daily production for 2003, a $1.00 per barrel change in the weighted average realized oil price would have increased or decreased revenues for the year by approximately $125,000 and a $.10 per Mcf change in the weighted average realized price of natural gas would have increased or decreased revenues for the year by approximately $143,000. The Partnership did not use derivative financial instruments or otherwise engage in hedging activities during the three-year period ended December 31, 2003. Due to the volatility of commodity prices, the Partnership is not in a position to predict future oil and gas prices.

If oil and gas prices decline significantly in the future, even if only for a short period of time, it is possible that non-cash write-downs of the Partnership's oil and gas properties could occur under the full cost accounting rules of the SEC. Under these rules, the Partnership reviews the carrying value of its proved oil and gas properties each quarter to ensure the capitalized costs of proved oil and gas properties, net of accumulated depreciation, depletion and amortization do not exceed the "ceiling". This ceiling is the present value of estimated future net cash flows from proved oil and gas reserves, discounted at 10 percent. If capitalized costs exceed this limit, the excess is charged to additional DD&A expense. The calculation of estimated future net cash flows is based on the prices for crude oil and natural gas in effect on the last day of each fiscal quarter except for volumes sold under long-term contracts. Write-downs required by these rules do not impact cash flow from operating activities, however, as discussed above, sustained low prices would have a material adverse effect on future cash flows.

FORWARD-LOOKING STATEMENTS AND RISK

Certain statements in this report, including statements of the future plans, objectives, and expected performance of the Partnership, are forward-looking statements that are dependent upon certain events, risks and uncertainties that may be outside the Partnership's control, and which could cause actual results to differ materially from those anticipated. Some of these include, but are not limited to, the market prices of oil and gas, economic and competitive conditions, inflation rates, legislative and regulatory changes, financial market conditions, political and economic uncertainties of foreign governments, future business decisions, and other uncertainties, all of which are difficult to predict.

There are numerous uncertainties inherent in estimating quantities of proved oil and gas reserves and in projecting future rates of production and the timing of development expenditures. The total amount or timing of actual future production may vary significantly from reserves and production estimates. The drilling of development wells can involve risks, including those related to timing and cost overruns. Lease and rig availability, complex geology and other factors can affect these risks. Fluctuations in oil and gas prices, or a prolonged period of low prices, may substantially adversely affect the Partnership's financial position, results of operations and cash flows.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

APACHE OFFSHORE INVESTMENT PARTNERSHIP
INDEX TO FINANCIAL STATEMENTS

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Schedules -

All financial statement schedules have been omitted because they are either not required, not applicable or the information required to be presented is included in the financial statements or related notes thereto.

REPORT OF INDEPENDENT AUDITORS

To the Partners of Apache Offshore Investment Partnership:

We have audited the accompanying consolidated balance sheets of Apache Offshore Investment Partnership (a Delaware general partnership) and subsidiary as of December 31, 2003 and 2002, and the related consolidated statements of income, cash flows and changes in partners' capital for each of the two years in the period ended December 31, 2003. These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these financial statements based on our audits. The financial statements of Apache Offshore Investment Partnership as of December 31, 2001, and for the year then ended, were audited by other auditors who have ceased operations and whose report, dated March 1, 2002, expressed an unqualified opinion on those financial statements.

We conducted our audits in accordance with auditing standards generally accepted in the United States. 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 Apache Offshore Investment Partnership as of December 31, 2003 and 2002, and the results of its operations and its cash flows for each of the two years in the period ended December 31, 2003 in conformity with accounting principles generally accepted in the United States.

As discussed above, the financial statements of Apache Offshore Investment Partnership as of December 31, 2001, and for the year then ended, were audited by other auditors who have ceased operations. As described in Note 2, these financial statements have been revised to reflect third party gathering and transportation costs as an operating cost instead of a reduction of revenues as previously reported. We audited the adjustments described in Note 2 that were applied to revise the 2001 consolidated statement of operations. In our opinion, such adjustments are appropriate and have been properly applied. However, we were not engaged to audit, review, or apply any procedures to the 2001 financial statements of Apache Offshore Investment Partnership other than with respect to such adjustments and, accordingly, we do not express an opinion or any other form of assurance on the 2001 financial statements taken as a whole.

As discussed in Note 8 to the consolidated financial statements, effective January 1, 2003, the Partnership changed its method of accounting for Asset Retirement Obligations.

ERNST & YOUNG LLP

Houston, Texas
March 11, 2004

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

To the Partners of Apache Offshore Investment Partnership:

We have audited the accompanying consolidated balance sheet of Apache Offshore Investment Partnership (a Delaware general partnership) and subsidiary as of December 31, 2001 and 2000, and the related consolidated statements of income, cash flows and changes in partners' capital for each of the three years in the period ended December 31, 2001. These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States. 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 Apache Offshore Investment Partnership as of December 31, 2001 and 2000, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2001, in conformity with accounting principles generally accepted in the United States.

ARTHUR ANDERSEN LLP

Houston, Texas
March 1, 2002

THIS IS A COPY OF AN ACCOUNTANT'S REPORT PREVIOUSLY ISSUED BY ARTHUR ANDERSEN LLP, AND HAS NOT BEEN REISSUED BY ARTHUR ANDERSEN. SEE PART II, ITEM 9 FOR FURTHER INFORMATION.

APACHE OFFSHORE INVESTMENT PARTNERSHIP
STATEMENT OF CONSOLIDATED INCOME

	FOR THE YEAR ENDED DECEMBER 31, 2003	2002	2001
REVENUES:			
Oil and gas sales	$ 11,950,908	$ 6,867,523	$ 10,494,911
Interest income	27,081	19,199	75,126
Other revenue	14,567	99,300	-
	11,992,556	6,986,022	10,570,037
OPERATING EXPENSES:			
Depreciation, depletion and amortization	2,875,896	2,181,189	2,042,461
Asset retirement obligation accretion	37,605	-	-
Lease operating costs	818,636	731,416	635,049
Gathering and transportation expense	121,067	102,698	148,282
Administrative	405,000	447,000	480,000
	4,258,204	3,462,303	3,305,792
Operating income before cumulative effect of change in accounting principle	$ 7,734,352	$ 3,523,719	$ 7,264,245
Cumulative effect of change in accounting principle	302,407	-	-
NET INCOME	$ 8,036,759	$ 3,523,719	$ 7,264,245
NET INCOME ALLOCATED TO:			
Managing Partner	$ 2,036,681	$ 1,035,747	$ 1,730,985
Investing Partners	6,000,078	2,487,972	5,533,260
	$ 8,036,759	$ 3,523,719	$ 7,264,245
NET INCOME PER INVESTING PARTNER UNIT	$ 5,598	$ 2,259	$ 4,922
WEIGHTED AVERAGE INVESTING PARTNER UNITS OUTSTANDING	1,071.9	1,101.5	1,124.1

The accompanying notes to financial statements are
an integral part of this statement.

APACHE OFFSHORE INVESTMENT PARTNERSHIP
STATEMENT OF CONSOLIDATED CASH FLOWS

	FOR THE YEAR ENDED DECEMBER 31, 2003	2002	2001
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$ 8,036,759	$ 3,523,719	$ 7,264,245
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	2,875,896	2,181,189	2,042,461
Asset retirement obligation accretion	37,605	-	-
Cumulative effect of change in accounting principle	(302,407)	-	-
Dismantlement and abandonment cost	(254,134)	-	-
Changes in operating assets and liabilities:			
(Increase) decrease in accrued revenues receivable	(26,046)	(322,209)	731,343
Increase (decrease) in accrued operating expenses	3,598	(63,706)	27,400
Increase (decrease) in payable to Apache Corporation	(210,169)	(392,810)	125,507
Net cash provided by operating activities	10,161,102	4,926,183	10,190,956
CASH FLOWS FROM INVESTING ACTIVITIES:			
Additions to oil and gas properties	(1,916,566)	(3,248,104)	(3,030,327)
Increase (decrease) in accrued development costs	282,927	(362,745)	(96,442)
Net cash used in investing activities	(1,633,639)	(3,610,849)	(3,126,769)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Repurchase of Partnership Units	(295,734)	(213,006)	(195,221)
Distributions to Investing Partners	(4,789,313)	(1,095,189)	(4,501,620)
Distributions to Managing Partner, net	(2,086,812)	(974,634)	(1,926,838)
Net cash used in financing activities	(7,171,859)	(2,282,829)	(6,623,679)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	1,355,604	(967,495)	440,508
CASH AND CASH EQUIVALENTS, BEGINNING OF YEAR	915,891	1,883,386	1,442,878
CASH AND CASH EQUIVALENTS, END OF YEAR	$ 2,271,495	$ 915,891	$ 1,883,386

The accompanying notes to financial statements are an integral part of this statement.

APACHE OFFSHORE INVESTMENT PARTNERSHIP
CONSOLIDATED BALANCE SHEET

	DECEMBER 31, 2003	DECEMBER 31, 2002
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 2,271,495	$ 915,891
Accrued revenues receivable	641,210	615,164
Receivable from Apache Corporation	86,217	-
	2,998,922	1,531,055
OIL AND GAS PROPERTIES, on the basis of full cost accounting:		
Proved properties	182,173,899	179,656,827
Less - Accumulated depreciation, depletion and amortization	(173,498,689)	(171,353,743)
	8,675,210	8,303,084
	$ 11,674,132	$ 9,834,139
LIABILITIES AND PARTNERS' CAPITAL		
CURRENT LIABILITIES:		
Accrued development costs	$ 334,740	$ 51,813
Accrued operating expenses	52,076	48,478
Payable to Apache Corporation	-	123,952
	386,816	224,243
COMMITMENTS AND CONTINGENCIES (Note 7)		
ASSET RETIREMENT OBLIGATION	812,520	-
PARTNERS' CAPITAL:		
Managing Partner	167,210	217,341
Investing Partners (1,060.7 and 1,084.9 Units outstanding, respectively)	10,307,586	9,392,555
	10,474,796	9,609,896
	$ 11,674,132	$ 9,834,139

The accompanying notes to financial statements are
an integral part of this statement.

APACHE OFFSHORE INVESTMENT PARTNERSHIP
STATEMENT OF CONSOLIDATED CHANGES IN PARTNERS' CAPITAL

	MANAGING PARTNER	INVESTING PARTNERS	TOTAL
BALANCE, DECEMBER 31, 2000	$ 352,081	$ 7,376,359	$ 7,728,440
Distributions, net	(1,926,838)	(4,501,620)	(6,428,458)
Repurchase of Partnership Units	-	(195,221)	(195,221)
Net income	1,730,985	5,533,260	7,264,245
BALANCE, DECEMBER 31, 2001	156,228	8,212,778	8,369,006
Distributions, net	(974,634)	(1,095,189)	(2,069,823)
Repurchase of Partnership Units	-	(213,006)	(213,006)
Net income	1,035,747	2,487,972	3,523,719
BALANCE, DECEMBER 31, 2002	217,341	9,392,555	9,609,896
Distributions, net	(2,086,812)	(4,789,313)	(6,876,125)
Repurchase of Partnership Units	-	(295,734)	(295,734)
Net income	2,036,681	6,000,078	8,036,759
BALANCE, DECEMBER 31, 2003	$ 167,210	$ 10,307,586	$ 10,474,796

The accompanying notes to financial statements are
an integral part of this statement.

(1) ORGANIZATION

NATURE OF OPERATIONS -

Apache Offshore Investment Partnership was formed as a Delaware general partnership on October 31, 1983, consisting of Apache Corporation (Apache) as Managing Partner and public investors as Investing Partners. The general partnership invested its entire capital in Apache Offshore Petroleum Limited Partnership, a Delaware limited partnership formed to conduct oil and gas exploration, development and production operations. The accompanying financial statements include the accounts of both the limited and general partnerships. Apache is the general partner of both the limited and general partnerships, and held approximately five percent of the 1,060.7 Investing Partner Units (Units) outstanding at December 31, 2003. The term "Partnership", as used hereafter, refers to the limited or the general partnership, as the case may be.

The Partnership purchased, at cost, an 85 percent interest in offshore leasehold interests acquired by Apache as a co-venturer in a series of oil and gas exploration, development and production activities on 87 federal lease tracts in the Gulf of Mexico, offshore Louisiana and Texas. The remaining 15 percent interest was purchased by an affiliated partnership or retained by Apache. The Partnership acquired an increased net revenue interest in Matagorda Island Blocks 681 and 682 in November 1992, when the Partnership and Apache formed a joint venture to acquire a 92.6 percent working interest in the blocks.

Since inception, the Partnership has participated in 14 federal offshore lease sales in which 49 prospects were acquired (through the same date 43 of those prospects have been surrendered/sold). The Partnership's working interests in the six remaining venture prospects range from 6.29 percent to 7.08 percent. As of December 31, 2003, the Partnership held a remaining interest in 11 tracts acquired through federal lease sales and two tracts obtained through farmout arrangements.

The Partnership's future financial condition and results of operations will depend largely upon prices received for its oil and natural gas production and the costs of acquiring, finding, developing and producing reserves. A substantial portion of the Partnership's production is sold under market-sensitive contracts. Prices for oil and natural gas are subject to fluctuations in response to changes in supply, market uncertainty and a variety of factors beyond the Partnership's control. These factors include worldwide political instability (especially in the Middle East), the foreign supply of oil and natural gas, the price of foreign imports, the level of consumer demand, and the price and availability of alternative fuels. With natural gas accounting for 65 percent of the Partnership's 2003 production and 62 percent of total proved reserves, on an energy equivalent basis, the Partnership is affected more by fluctuations in natural gas prices than in oil prices.

Under the terms of the Partnership Agreements, the Investing Partners receive 80 percent and Apache receives 20 percent of revenue. Lease operating, gathering and transportation and administrative expenses are allocated to the Investing Partners and Apache in the same proportion as revenues. The Investing Partners receive 100 percent of the interest income earned on short-term cash investments. The Investing Partners generally pay for 90 percent and Apache generally pays for 10 percent of exploration and development costs and expenses incurred by the Partnership. However, intangible drilling costs, interest costs and fees or expenses related to the loans incurred by the Partnership are allocated 99 percent to the Investing Partners and one percent to Apache until such time as the amount so allocated to the Investing Partners equals 90 percent of the total amount of such costs, including such costs incurred by Apache prior to the formation of the Partnerships.

RIGHT OF PRESENTMENT -

An amendment to the Partnership Agreements adopted in February 1994, created a right of presentment under which all Investing Partners have a limited and voluntary right to offer their Units to the Partnership twice each year to be purchased for cash. During 2003, the Investing Partners sold a total of 24.2 Units to the Partnership for a total of $295,734 in cash. The first right of presentment was based upon a valuation date of December 31, 2002 for a purchase price of $12,047 per Unit, plus interest to the date of payment. The second presentment offer was based on a valuation date of June 30, 2003 for a purchase price of $9,512 per Unit, plus interest to the payment date. During 2002 and 2001, the Partnership paid the Investing Partners $213,006 and $195,221, respectively, to acquire a total of 43.6 Units.

The Partnership is not in a position to predict how many Units will be presented for repurchase during 2004, however, no more than 10 percent of the outstanding Units may be purchased under the right of presentment in any year. The Partnership has no obligation to purchase any Units presented to the extent that it determines that it has insufficient funds for such purchases.

The table below sets forth the total repurchase price and the repurchase price per Unit for all outstanding Units at each presentment period, based on the right of presentment valuation formula defined in the amendment to the Partnership Agreement. The right of presentment offers, made twice annually, are based on a discounted Unit value formula. The discounted Unit value will be not less than the Investing Partner's share of: (a) the sum of (i) 70 percent of the discounted estimated future net revenues from proved reserves, discounted at a rate of 1.5 percent over prime or First National Bank of Chicago's base rate in effect at the time the calculation is made, (ii) cash on hand, (iii) prepaid expenses, (iv) accounts receivable less a reasonable reserve for doubtful accounts, (v) oil and gas properties other than proved reserves at cost less any amounts attributable to drilling and completion costs incurred by the Partnership and included therein, and (vi) the book value of all other assets of the Partnership, less the debts, obligations and other liabilities of all kinds (including accrued expenses) then allocable to such interest in the Partnership, all determined as of the valuation date, divided by (b) the number of Units, and fractions thereof, outstanding as of the valuation date. The discounted Unit value does not purport to be, and may be substantially different from, the fair market value of a Unit.

RIGHT OF PRESENTMENT VALUATION DATE	TOTAL REPURCHASE PRICE	REPURCHASE PRICE PER UNIT
December 31, 2000	$ 13,460,392	$ 9,928
June 30, 2001	13,984,141	10,460
December 31, 2001	9,644,386	8,686
June 30, 2002	9,157,842	7,362
December 31, 2002	13,612,220	12,047
June 30, 2003	14,345,895	9,512

INVESTING PARTNER UNITS OUTSTANDING:	2003	2002	2001
Balance, beginning of year	1,084.9	1,110.3	1,128.5
Repurchase of Partnership Units	(24.2)	(25.4)	(18.2)
Balance, end of year	1,060.7	1,084.9	1,110.3

CAPITAL CONTRIBUTIONS -

A total of $85,000 per Unit, or approximately 57 percent, of investor subscription had been called through December 31, 2003. The Partnership determined the full purchase price of $150,000 per Unit was not needed, and upon completion of the last subscription call in November 1989, released the Investing Partners from their remaining liability. As a result of investors defaulting on cash calls and repurchases under the presentment offer discussed above, the original 1,500 Units have been reduced to 1,060.7 Units at December 31, 2003.

(2) SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

STATEMENT PRESENTATION -

The accounts of the Partnerships are maintained on a tax basis method of accounting in accordance with the Articles of Partnership and methods of reporting allowed for federal income tax purposes.

The consolidated financial statements included in reports that the Partnership files with the Securities and Exchange Commission (SEC) are required to be prepared in conformity with generally accepted accounting principles. Accordingly, the accompanying consolidated financial statements include adjustments to convert from tax basis to the accrual basis method in conformity with accounting principles generally accepted in the United States.

The accompanying consolidated financial statements include the accounts of Apache Offshore Investment Partnership and Apache Offshore Petroleum Limited Partnership after elimination of intercompany balances and transactions.

CASH EQUIVALENTS -

The Partnership considers all highly liquid debt instruments purchased with an original maturity of three months or less to be cash equivalents. These investments are carried at cost which approximates market.

OIL AND GAS PROPERTIES -

The Partnership uses the full cost method of accounting for its investment in oil and gas properties for financial statement purposes. Under this method, the Partnership capitalizes all acquisition, exploration and development costs incurred for the purpose of finding oil and gas reserves. The amounts capitalized under this method include dry hole costs, leasehold costs, engineering, geological, exploration, development and other similar costs. Costs associated with production and administrative functions are expensed in the period incurred. Unless a significant portion of the Partnership's reserve volumes are sold (greater than 25 percent), proceeds from the sale of oil and gas properties are accounted for as reductions to capitalized costs, and gains or losses are not recognized.

Capitalized costs of oil and gas properties are amortized on the future gross revenue method whereby depreciation, depletion and amortization (DD&A) expense is computed quarterly by dividing current period oil and gas sales by estimated future gross revenue from proved oil and gas reserves (including current period oil and gas sales) and applying the resulting rate to the net cost of evaluated oil and gas properties, including estimated future development costs. The amortizable base includes estimated dismantlement, restoration and abandonment costs, net of estimated salvage values. Beginning in 2003, the Partnership changed its method of accounting for dismantlement, restoration and abandonment cost as described in Note 8.

In performing its quarterly ceiling test, the Partnership limits the capitalized costs of proved oil and gas properties, net of accumulated DD&A, to the estimated future net cash flows from proved oil and gas reserves discounted at 10 percent, plus the lower of cost or fair value of unproved properties included in the costs being amortized, if any. If capitalized costs exceed this limit, the excess is charged to DD&A expense. The Partnership has not recorded any write-downs of capitalized costs for the three years presented. Please see "Future Net Cash Flows" in the Supplemental Oil and Gas Disclosures included in this Form 10-K for a discussion on calculation of estimated future net cash flows.

Given the volatility of oil and gas prices, it is reasonably possible that the Partnership's estimate of discounted future net cash flows from proved oil and gas reserves could change in the near term. If oil and gas prices decline significantly, even if only for a short period of time, it is possible that write-downs of oil and gas properties could occur in the future.

The Partnership has taken note of a July 2003 inquiry to the Financial Accounting Standards Board (FASB) regarding whether or not contract-based oil and gas mineral rights held by lease or contract ("mineral rights") should be recorded or disclosed as intangible assets. The inquiry presents a view that these mineral rights are intangible assets as defined in Statement of Financial Accounting Standards (SFAS) No. 141, "Business Combinations," and, therefore, should be classified separately on the balance sheet as intangible assets. SFAS No. 141, and SFAS No. 142, "Goodwill and Other Intangible Assets," became effective for transactions subsequent to June 30, 2001 with the disclosure requirements of SFAS No. 142 required as of January 1, 2002. SFAS No. 141 requires that all business combinations initiated after June 30, 2001 be accounted for using the purchase method and that intangible assets be disaggregated and reported separately from goodwill. SFAS No. 142 established new accounting guidelines for both finite lived intangible assets and indefinite lived intangible assets. Under the statement, intangible assets should be separately reported on the face of the balance sheet and accompanied by disclosure in the notes to financial statements. SFAS No. 142 scopes out accounting utilized by the oil and gas industry as prescribed by SFAS No. 19, and is silent about whether or not its disclosure provisions apply to oil and gas companies. The Partnership does not believe that SFAS No. 141 or 142 change the classification of oil and gas mineral rights and the Partnership continues to classify these assets as part of oil and gas properties. The Emerging Issues Task Force (EITF) has added the treatment of oil and gas mineral rights to an upcoming agenda, which may result in a change in how the Partnership classifies these assets.

The Partnership has not participated in any business combinations or major asset purchases since the June 30, 2001 effective date of SFAS No. 141 and SFAS No. 142, and believes it will not be impacted by the EITF's decisions regarding the accounting treatment for oil and gas mineral interests. The Partnership has not historically tracked the amount of mineral rights in the proved property balance related to producing leases or relinquished leases.

Based on the Partnership's understanding of the issue before the EITF, if all mineral rights associated with unevaluated property and producing reserves were deemed to be intangible assets:

- mineral rights with proved reserves that were acquired after June 30, 2001 and mineral rights with no proved reserves would be classified as intangible assets and would not be included in oil and gas properties on our consolidated balance sheet;

- results of operations and cash flows would not be materially affected because mineral rights would continue to be amortized in accordance with full cost accounting rules; and

- disclosures required by SFAS Nos. 141 and 142 relative to intangibles would be included in the notes to our financial statements.

If the accounting for mineral rights is ultimately changed, transitional guidance for intangible assets permits the reclassification of only amounts acquired after the effective date of SFAS Nos. 141 and 142 if records were not previously maintained to track acquisition costs based on their intangible or tangible nature. Lack of these records prior to the effective date could result in the loss of comparability between historical balances of tangible and intangible asset balances and among companies in the industry.

REVENUE RECOGNITION -

Oil and gas revenues are recognized when production is sold to a purchaser at a fixed or determinable price, when delivery has occurred and title has transferred, and if collectibility of the revenue is probable. The Partnership uses the sales method of accounting for natural gas revenues. Under this method, revenues are recognized based on actual volumes of gas sold to purchasers. The volumes of gas sold may differ from the volumes to which the Partnership is entitled based on its interests in the properties. These differences create imbalances that are recognized as a liability only when the estimated remaining reserves will not be sufficient to enable the underproduced owner to recoup its entitled share through production. As of December 31, 2003 and 2002, the Partnership did not have any liabilities for gas imbalances in excess of remaining reserves. No receivables are recorded for those wells where the Partnership has taken less than its share of production. Gas imbalances are reflected as adjustments to proved gas revenues and future cash flows in the unaudited

supplemental oil and gas disclosures. Adjustments for gas imbalances totaled less than one percent of the Partnership's proved gas reserves at December 31, 2003, 2002 and 2001.

NET INCOME PER INVESTING UNIT -

The net income per Investing Partner Unit is calculated by dividing the aggregate Investing Partners' net income for the period by the number of weighted average Investing Partner Units outstanding for that period.

INCOME TAXES -

The profit or loss of the Partnership for federal income tax reporting purposes is included in the income tax returns of the partners. Accordingly, no recognition has been given to income taxes in the accompanying financial statements.

USE OF ESTIMATES -

The preparation of financial statements in conformity with accounting principles generally accepted in the United States 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. Certain accounting policies involve judgments and uncertainties to such an extent that there is a reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. The Partnership bases its estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances. Actual results could differ from those estimates. Significant estimates with regard to these financial statements include the estimate of proved oil and gas reserve quantities and the related present value of estimated future net cash flows therefrom. See unaudited "Supplemental Oil and Gas Disclosures" below.

RECEIVABLE FROM/PAYABLE TO APACHE -

The receivable from/payable to Apache represents the net result of the Investing Partners' revenue and expenditure transactions in the current month. Generally, cash in this amount will be paid by Apache to the Partnership or transferred to Apache in the month after the Partnership's transactions are processed and the net results from operations are determined.

MAINTENANCE AND REPAIRS -

Maintenance and repairs are charged to expense as incurred.

RECLASSIFICATIONS -

To comply with the consensus reached on Emerging Issues Task Force Issue 00-10, "Accounting for Shipping and Handling Fees and Costs", third party gathering and transportation costs have been reported as an operating cost instead of a reduction of revenues as previously reported. Reclassifications have been made to reflect this change in prior period statements of consolidated income.

COMPENSATION TO APACHE

Apache is entitled to the following types of compensation and reimbursement for costs and expenses.

	TOTAL REIMBURSED BY THE INVESTING PARTNERS FOR THE YEAR ENDED DECEMBER 31,		
	2003	2002	2001
		(In thousands)	
a. Apache is reimbursed for general, administrative and overhead expenses incurred in connection with the management and operation of the Partnership's business	$ 324	$ 358	$ 384
b. Apache is reimbursed for development overhead costs incurred in the Partnership's operations. These costs are based on development activities and are capitalized to oil and gas properties	$ 86	$ 129	$ 147

Apache operates certain Partnership properties. Billings to the Partnership are made on the same basis as to unaffiliated third parties or at prevailing industry rates.

(4) OIL AND GAS PROPERTIES

The following tables contain direct cost information and changes in the Partnership's oil and gas properties for each of the years ended December 31. All costs of oil and gas properties are currently being amortized.

	2003	2002	2001
		(In thousands)	
Oil and Gas Properties			
Balance, beginning of year	$ 179,657	$ 176,409	$ 173,378
Asset retirement cost from adoption of SFAS No. 143 -			
Investing Partners	323	-	-
Managing Partner	3	-	-
Costs incurred during the year:			
Development -			
Investing Partners	2,154	3,174	2,962
Managing Partner	37	74	69
Balance, end of year	$ 182,174	$ 179,657	$ 176,409

	MANAGING PARTNER	INVESTING PARTNERS	TOTAL
		(In thousands)	
Accumulated Depreciation, Depletion and Amortization			
Balance, December 31, 2000	$ 20,465	$ 146,665	$ 167,130
Provision	116	1,927	2,043
Balance, December 31, 2001	20,581	148,592	169,173
Provision	101	2,080	2,181
Balance, December 31, 2002	20,682	150,672	171,354
Adoption of SFAS No. 143	(7)	(724)	(731)
Provision	90	2,786	2,876
Balance, December 31, 2003	$ 20,765	$ 152,734	$ 173,499

The Partnership's aggregate DD&A expense as a percentage of oil and gas sales for 2003, 2002 and 2001 was 24 percent, 32 percent and 19 percent, respectively.

(5) MAJOR CUSTOMER AND RELATED PARTIES INFORMATION

Revenues received from major third party customers that exceeded 10 percent of oil and gas sales are discussed below. No other third party customers individually accounted for more than ten percent of oil and gas sales.

Effective with July 2003 production, the Managing Partner began directly marketing the Partnership's and its own U.S. natural gas production. Most of the Partnership's natural gas production was previously marketed through Cinergy Marketing and Trading, LLC (Cinergy) under a gas sales agreement between the Managing Partner and Cinergy. The Partnership believes that the prices it receives for natural gas are comparable to the prices it would have received from Cinergy.

Sales to Cinergy Marketing & Trading, LLC (Cinergy) accounted for 37 percent, 60 percent and 73 percent of the Partnership's oil and gas sales in 2003, 2002 and 2001, respectively. In 1998, Apache formed a strategic alliance with Cinergy Corp. to market substantially all of Apache's natural gas production from North America and sold its 57 percent interest in Producers Energy Marketing LLC (ProEnergy) to Cinergy Corp. In July 1998, in connection with the sale of its interest, Apache entered into a gas purchase agreement with Cinergy to market most of Apache's North American natural gas production for 10 years, with an option, after prior notice, to terminate after six years. Apache also sold most of the Partnership's natural gas production to Cinergy under the gas purchase agreement. Since 2001, Apache had been involved in an arbitration proceeding with Cinergy on issues arising from the gas sales agreement. Apache's resolution of these disputes with Cinergy in mid-2003 did not have a material effect on the Partnership's financial position or sales.

Apache Crude Oil Marketing, Inc., a wholly-owned subsidiary of Apache, purchased oil and condensate from the Partnership which accounted for approximately 17 percent and 26 percent of the Partnership's total oil and gas sales in 2002 and 2001, respectively. The prices the Partnership received for these sales were based on third-party pricing indexes, and in the opinion of Apache, comparable to prices that would have been received from a non-affiliated party.

Sales to Chevron Texaco accounted for 32 percent and 21 percent of the Partnership's oil and gas sales in 2003 and 2002, respectively.

Effective November 1992, with Apache's and the Partnership's acquisition of an additional net revenue interest in Matagorda Island Blocks 681 and 682, a wholly-owned subsidiary of Apache purchased from Shell Oil Company (Shell) a 14.4 mile natural gas and condensate pipeline connecting Matagorda Island Block 681 to onshore markets. The Partnership paid the Apache subsidiary transportation fees totaling $43,606 in 2003, $43,785 in 2002 and $45,147 in 2001 for the Partnership's share of gas. The fees were at the same rates and terms as previously paid to Shell.

All transactions with related parties were consumated at fair value.

The Partnership's revenues are derived principally from uncollateralized sales to customers in the oil and gas industry; therefore, customers may be similarly affected by changes in economic and other conditions within the industry. The Partnership has not experienced material credit losses on such sales.

(6) FINANCIAL INSTRUMENTS

The carrying amount of cash and cash equivalents, accrued revenues receivables and accrued costs included in the accompanying balance sheet approximated their fair values at December 31, 2003 and 2002 due to their short maturities. The Partnership did not use derivative financial instruments or otherwise engage in hedging activities during the three-year period ended December 31, 2003.

(7) COMMITMENTS AND CONTINGENCIES

Litigation - The Partnership is involved in litigation and is subject to governmental and regulatory controls arising in the ordinary course of business. It is the opinion of the Apache's management that all claims and litigation involving the Partnership are not likely to have a material adverse effect on its financial position or results of operations.

Environmental - The Partnership, as an owner or lessee of interests in oil and gas properties, is subject to various federal, state, local and foreign country laws and regulations relating to discharge of materials into, and protection of, the environment. These laws and regulations may, among other things, impose liability on the lessee under an oil and gas lease for the cost of pollution clean-up resulting from operations and subject the lessee to liability for pollution damages. Apache maintains insurance coverage on the Partnership's properties, which it believes, is customary in the industry, although it is not fully insured against all environmental risks.

(8) NEW ACCOUNTING PRONOUCEMENTS

In June 2001 the FASB issued SFAS No. 143 "Accounting for Asset Retirement Obligations." SFAS No. 143 requires that an asset retirement obligation (ARO) associated with the retirement of a tangible long-lived asset be recognized as a liability in the period in which a legal obligation is incurred and becomes determinable, with an offsetting increase in the carrying amount of the associated asset. The cost of the tangible asset, including the initially recognized ARO, is depleted such that the cost of the ARO is recognized over the useful life of the asset. The ARO is recorded at fair value, and accretion expense will be recognized over time as the discounted liability is accreted to its expected settlement value. The fair value of the ARO is measured using expected future cash outflows discounted at the company's credit-adjusted risk-free interest rate.

Effective January 1, 2003, the Partnership adopted SFAS No. 143 which resulted in an increase to net oil and gas properties of $1.1 million and additional liabilities related to asset retirement obligations of $.8 million. These amounts reflect the ARO of the Partnership had the provisions of SFAS No. 143 been applied since inception and resulted in a non-cash cumulative-effect increase in net income of $.3 million. In accordance with the provisions of SFAS No. 143, the Partnership records an abandonment liability associated with its oil and gas wells and platforms when those assets are placed in service, rather than its past practice of accruing the expected abandonment costs over the productive life of the associated full-cost pool. Under SFAS No. 143 depletion expense is reduced since a discounted ARO is depleted in the property balance rather than the undiscounted value previously depleted under the old rules. The lower depletion expense under SFAS No. 143

is offset, however, by accretion expense, which is recognized over time as the discounted liability is accreted to its expected settlement value.

Inherent in the fair value calculation of ARO are numerous assumptions and judgments including the ultimate settlement amounts, inflation factors, credit adjusted discount rates, timing of settlement, and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the fair value of the existing ARO liability, a corresponding adjustment is made to the oil and gas property balance.

The $.3 million cumulative increase to earnings upon adoption did not take into consideration potential impacts of adopting SFAS No. 143 on previous full-cost property impairment tests. The Partnership chose not to re-calculate historical full-cost impairment tests ("ceiling test") upon adoption even though historical oil and gas property balances would have been higher had the Partnership applied the provisions of the statement. Management believes this approach is appropriate because SFAS No. 143 is silent on this issue and was not effective during the prior ceiling test periods. Had the Partnership re-calculated the historical full-cost ceiling tests and included the impact as a component of the cumulative effect of adoption, the ultimate gain recognized would have potentially been reduced. A ceiling test calculation was performed upon adoption and at the end of each reporting period subsequent to adoption and no impairment was necessary. In calculating ceiling limitations, the Partnership includes the undiscounted ARO as part of future development costs, essentially reducing the present value of its future net revenues and full-cost ceiling limit. To compare the property balance, which included the ARO component, to the full-cost ceiling limit, which has been reduced by a similar abandonment cost, the Partnership nets the ARO liability against the property balance. The Partnership believes this is appropriate since there must be a comparable basis between the net book value of the properties and the full-cost ceiling limitation.

The following table is a reconciliation of the asset retirement obligation liability since adoption (in thousands):

Asset retirement obligation upon adoption on January 1, 2003	$ 754,351
Liabilities settled	(575,553)
Accretion expense	37,605
Revisions in estimated liabilities	596,117
Asset retirement obligation at December 31, 2003	$ 812,520

The upward revision in estimated liabilities during 2003 resulted from new information provided by outside operators on the East Cameron 60 and Ship Shoal 258/259 Fields.

The pro forma asset retirement obligation would have been approximately $.7 million at January 1, 2002 had the Company adopted the provisions of SFAS No. 143 on January 1, 2002. If the Partnership had not adopted SFAS No. 143 in 2003, the Partnership's operating income before the cumulative effect of the change in accounting principle would not have been materially different then the amount reported for 2003. The following table shows the pro forma effect of the implementation on the Partnership's net income had SFAS No. 143 been adopted by the Company on January 1, 2001.

	FOR THE YEAR ENDED DECEMBER 31,	
	2002	2001
	(IN THOUSANDS)	
Net income, as reported	$ 3,524	$ 7,264
Effect on net income had SFAS No. 143 been applied	(35)	(33)
Net income, as adjusted	$ 3,489	$ 7,231

In January 2003, the FASB issued Interpretation No. 46 "Consolidation of Variable Interest Entities, an Interpretation of Accounting Research

Bulletin No. 51." Interpretation No. 46 requires a company to consolidate a variable interest entity (VIE) if the company has a variable interest (or combination of variable interests) that is exposed to a majority of the entity's expected losses if they occur, receive a majority of the entity's expected residual returns if they occur, or both. In addition, more extensive disclosure requirements apply to the primary and other significant variable interest owners of the VIE. This interpretation applies immediately to VIEs created after January 31, 2003, and to VIEs in which an enterprise obtains an interest after that date. It is also effective for the first fiscal year or interim period beginning after December 31, 2003, to VIEs in which a company holds a variable interest that is acquired before February 1, 2003. This interpretation did not affect the Partnership's consolidated financial statements.

(9) INSURANCE RECOVERIES

During 2003, the Partnership recognized insurance recoveries totaling $14,567 for the final amount of proceeds recoupable under business interruption insurance policies. The recoveries are included in other revenue in the accompanying Statement of Consolidated Income and reflect recoveries for the Partnership's share of lost oil and gas production resulting from hurricanes in 2002. The Partnership recognized $99,300 in 2002 for amounts recoupable under business interruption insurance policies.

(10) TAX-BASIS FINANCIAL INFORMATION

A reconciliation of ordinary income for federal income tax reporting purposes to net income under accounting principles generally accepted in the United States is as follows:

	2003	2002	2001
Net partnership ordinary income for federal income tax reporting purposes	$ 7,846,759	$ 2,426,766	$ 6,199,485
Plus: Items of current (income) expense for tax reporting purposes only -			
Intangible drilling cost	1,358,245	2,638,051	2,457,181
Dismantlement and abandonment cost	575,553	-	-
(Gain) on disposition of equipment	-	-	(258,053)
Tax depreciation	867,296	640,091	908,093
	2,801,094	3,278,142	3,107,221
Less: full cost DD&A expense	(2,875,896)	(2,181,189)	(2,042,461)
Less: asset retirement obligation accretion	(37,605)	-	-
Plus: cumulative effect of change in accounting principle	302,407	-	-
Net income	$ 8,036,759	$ 3,523,719	$ 7,264,245

The Partnership's tax bases in net oil and gas properties at December 31, 2003 and 2002 was $3,303,730 and $2,221,960, respectively, lower than carrying value of oil and gas properties under full cost accounting. The difference reflects the timing deductions for depreciation, depletion and amortization, intangible drilling costs and dismantlement and abandonment costs. For federal income tax reporting, the Partnership had capitalized syndication cost of $8,660,878 at December 31, 2003 and 2002.

A reconciliation of liabilities for federal income tax reporting purposes to liabilities under accounting principles generally accepted in the United States is as follows:

	DECEMBER 31, 2003	DECEMBER 31, 2002
Liabilities for federal income tax purposes	$ 386,816	$ 224,243
Asset retirement liability	812,520	-
Liabilities under accounting principles generally accepted in the United States	$ 1,199,336	$ 224,243

Asset retirement liabilities for future dismantlement and abandonment costs are not recognized for federal income tax reporting purposes.

APACHE OFFSHORE INVESTMENT PARTNERSHIP
SUPPLEMENTAL OIL AND GAS DISCLOSURES
(UNAUDITED)

OIL AND GAS RESERVE INFORMATION -

Proved oil and gas reserve quantities are based on estimates prepared by Ryder Scott Company, L.P., Petroleum Consultants, independent petroleum engineers, in accordance with guidelines established by the SEC. These reserves are subject to revision due to the inherent imprecision in estimating reserves, and are revised as additional information becomes available. All the Partnership's reserves are located offshore Texas and Louisiana.

There are numerous uncertainties inherent in estimating quantities of proved reserves and projecting future rates of production and timing of development expenditures. The following reserve data represents estimates only and should not be construed as being exact.

(Oil in Mbbls and gas in MMcf)

	2003		2002		2001	
	OIL	GAS	OIL	GAS	OIL	GAS
Proved Reserves						
Beginning of year	849	6,339	885	7,075	883	8,080
Extensions, discoveries and other additions	12	161	204	389	155	697
Revisions of previous estimates	(112)	924	(130)	99	(41)	3
Production	(131)	(1,432)	(110)	(1,224)	(112)	(1,705)
End of year	618	5,992	849	6,339	885	7,075
Proved Developed						
Beginning of year	849	6,230	767	6,685	736	7,462
End of year	618	5,883	849	6,230	767	6,685

Oil includes crude oil, condensate and natural gas liquids.

Approximately 62 percent of the Partnership's proved developed reserves are classified as proved not producing. These reserves relate to zones that are either behind pipe, or that have been completed but not yet produced or zones that have been produced in the past, but are not now producing due to mechanical reasons. These reserves may be regarded as less certain than producing reserves because they are frequently based on volumetric calculations rather than performance data. Future production associated with behind pipe reserves is scheduled to follow depletion of the currently producing zones in the same wellbores. It should be noted that additional capital may have to be spent to access these reserves. The capital and economic impact of production timing are reflected in the Partnership's standardized measure under Future Net Cash Flows.

APACHE OFFSHORE INVESTMENT PARTNERSHIP
SUPPLEMENTAL OIL AND GAS DISCLOSURES - (CONTINUED)
(UNAUDITED)

FUTURE NET CASH FLOWS -

The following table sets forth unaudited information concerning future net cash flows from proved oil and gas reserves. Future cash inflows are based on year-end prices. Operating costs and future development costs are based on current costs with no escalation. As the Partnership pays no income taxes, estimated future income tax expenses are omitted. This information does not purport to present the fair value of the Partnership's oil and gas assets, but does present a standardized disclosure concerning possible future net cash flows that would result under the assumptions used.

Discounted Future Net Cash Flows Relating to Proved Reserves

	DECEMBER 31,		
	2003	2002	2001
		(In thousands)	
Future cash inflows	$ 55,014	$ 56,471	$ 36,604
Future production costs	(5,645)	(4,623)	(4,440)
Future development costs	(3,789)	(4,115)	(4,937)
Net cash flows	45,580	47,733	27,227
10 percent annual discount rate	(14,995)	(16,908)	(9,794)
Discounted future net cash flows	$ 30,585	$ 30,825	$ 17,433

The following table sets forth the principal sources of change in the discounted future net cash flows:

	FOR THE YEAR ENDED DECEMBER 31,		
	2003	2002	2001
		(In thousands)	
Sales, net of production costs	$ (11,011)	$ (6,034)	$ (9,712)
Net change in prices and production costs	3,731	14,403	(43,479)
Extensions, discoveries and other additions	1,247	4,548	2,730
Development costs incurred	490	680	1,863
Revisions of quantities	813	(2,023)	(428)
Accretion of discount	3,083	1,743	6,532
Changes in future development costs	-	185	174
Changes in production rates and other	1,407	(110)	(5,570)
	$ (240)	$ 13,392	$ (47,890)

Impact of Pricing - The estimates of cash flows and reserve quantities shown above are based on year-end oil and gas prices. Forward price volatility is largely attributable to supply and demand perceptions for natural gas and oil.

Under full-cost accounting rules, the Partnership reviews the carrying value of its proved oil and gas properties each quarter. Under these rules, capitalized costs of proved oil and gas properties, net of accumulated DD&A, may not exceed the present value of estimated future net cash flows from proved oil and gas reserves, discounted at 10 percent (the "ceiling"). These rules generally require pricing future oil and gas production at the unescalated oil and gas prices at the end of each fiscal quarter and require a write-down if the "ceiling" is exceeded. Given the volatility of oil and gas prices, it is reasonably possible that the Partnership's estimate of discounted future net cash flows from proved oil and gas reserves could change in the near term. If oil and gas prices decline significantly, even if only for a short period of time, it is possible that write-downs of oil and gas properties could occur in the future.

APACHE OFFSHORE INVESTMENT PARTNERSHIP
SUPPLEMENTAL QUARTERLY FINANCIAL DATA
(UNAUDITED)

	FIRST	SECOND	THIRD	FOURTH	TOTAL
	(In thousands, except per Unit amounts)				
2003					
Revenues	$ 3,195	$ 3,021	$ 2,962	$ 2,815	$ 11,993
Expenses	1,151	1,061	1,051	995	4,258
Income before change in accounting principle	2,044	1,960	1,911	1,820	7,735
Cumulative effect of change in accounting principle	302	-	-	-	302
Net income	$ 2,346	$ 1,960	$ 1,911	$ 1,820	$ 8,037
Net income allocated to:					
Managing Partner	$ 536	$ 505	$ 509	$ 487	$ 2,037
Investing Partners	1,810	1,455	1,402	1,333	6,000
	$ 2,346	$ 1,960	$ 1,911	$ 1,820	$ 8,037
Net income per Investing Partner Unit (1)	$ 1,668	$ 1,348	$ 1,321	$ 1,256	$ 5,598
2002					
Revenues	$ 1,342	$ 1,787	$ 1,674	$ 2,183	$ 6,986
Expenses	704	896	892	970	3,462
Net income	$ 638	$ 891	$ 782	$ 1,213	$ 3,524
Net income allocated to:					
Managing Partner	$ 193	$ 260	$ 245	$ 338	$ 1,036
Investing Partners	445	631	537	875	2,488
	$ 638	$ 891	$ 782	$ 1,213	$ 3,524
Net income per Investing Partner Unit	$ 400	$ 570	$ 490	$ 799	$ 2,259

(1) The sum of the individual net income per Investing Partner Unit may not agree with the year-to-date net income per Investing Partner Unit as each quarterly computation is based on the weighted average number of Investing Partner Units during that period.

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

The financial statements for the fiscal year ended December 31, 2003 and 2002, included in this report, have been audited by Ernst & Young LLP, independent public auditors, as stated in their audit report appearing herein. The financial statements for the fiscal year ended December 31, 2001 and the year then ended, included in this report, were audited by Arthur Andersen LLP, independent public accountants, as stated in their audit report appearing herein. Arthur Andersen has not consented to the inclusion of their audit report in this report. For a discussion of the risks relating to Arthur Andersen's audit of our financial statements, please see "Risks relating to Arthur Andersen LLP" in Item 1.

Arthur Andersen's report on the Partnership's consolidated financial statements for the year ended December 31, 2001 and the year then ended, included elsewhere in this report, did not contain an adverse opinion or disclaimer of opinion, nor were they qualified or modified as to uncertainty, audit scope or accounting principles.

During the year ended December 31, 2001, and through the date we dismissed Arthur Andersen LLP, there were no disagreements with Arthur Andersen on any matter of accounting principle or practice, financial statement disclosure, or auditing scope or procedure which, if not resolved by Arthur Andersen's satisfaction, would have caused them to make reference to the subject matter in connection with their report on the Partnership's consolidated financial statements for such years; and there were no reportable events as set forth in applicable SEC regulations.

The General Partner provided Arthur Andersen LLP with a copy of the above disclosures on April 2, 2002. In a letter dated April 2, 2002, Arthur Andersen confirmed its agreement with these statements.

ITEM 9A. CONTROLS AND PROCEDURES

G. Steven Farris, the Managing Partner's President, Chief Executive Officer and Chief Operating Officer, and Roger B. Plank, the Managing Partner's Executive Vice President and Chief Financial Officer, evaluated the effectiveness of the Partnership's disclosure controls and procedures as of the end of the period covered by this report. Based on that evaluation and as of the date of that evaluation, these officers concluded that the Partnership's disclosure controls to be effective, providing effective means to insure that information it is required to disclose under applicable laws and regulations is recorded, processed, summarized and reported in a timely manner. We also made no significant changes in the Partnership's internal controls over financial reporting during the fiscal quarter ending December 31, 2003 that have materially affected, or are reasonably likely to materially affect, the Partnership's internal control over financial reporting.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE PARTNERSHIP

All management functions are performed by Apache, the Managing Partner of the Partnership. The Partnership itself has no officers or directors. Information concerning the officers and directors of Apache set forth under the captions "Nominees for Election as Directors", "Continuing Directors", "Executive Officers of the Company", and "Securities Ownership and Principal Holders" in the proxy statement relating to the 2004 annual meeting of stockholders of Apache (the Apache Proxy) is incorporated herein by reference.

Code of Business Conduct

Pursuant to Rule 303A.10 of the NYSE and Rule 4350(n) of the NASDAQ, Apache was required to adopt a code of business conduct and ethics for its directors, officers and employees. In February 2004, Apache's Board of Directors adopted a Code of Business Conduct (the "Code of Conduct"), which also meets the requirements of a code of ethics under Item 406 of Regulation S-K. You can access Apache's Code of Conduct on the Investor Relations page of the company's website at www.apachecorp.com. Changes in and waivers to the Code of Conduct for Apache's directors, chief executive officer and certain senior financial officers will be posted on the company's website within five business days and maintained for at least twelve months.

ITEM 11. EXECUTIVE COMPENSATION

See Note (3), "Compensation to Apache" of the Partnership's financial statements, under Item 8 above, for information regarding compensation to Apache as Managing Partner. The information concerning the compensation paid by Apache to its officers and directors set forth under the captions "Summary Compensation Table", "Option/SAR Exercises and Year-End Value Table", "Employment Contracts and Termination of Employment and Change-in-Control Arrangements", and "Director Compensation" in the Apache Proxy is incorporated herein by reference.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

Apache, as an Investing Partner and the General Partner, owns 53 Units, or 5.0 percent of the outstanding Units of the Partnership, as of December 31, 2003. Directors and officers of Apache own four Units, less than one percent of the Partnership's Units, as of December 31, 2003. Apache owns a one-percent General Partner interest (15 equivalent Units). To the knowledge of the Partnership, no Investing Partner owns, of record or beneficially, more than five percent of the Partnership's outstanding Units, except for Apache as General Partner which owns 53 Units or five percent of the outstanding Units.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

See Note (3), "Compensation to Apache" of the Partnership's financial statements, under Item 8 above, for information regarding compensation to Apache as Managing Partner. See Note (5), "Major Customers and Related Parties Information" of the Partnership's financial statements for amounts paid to subsidiaries of Apache, and for other related party information.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Accountant fees and services paid to Ernst & Young LLP, the Partnership's independent auditors, are included in amounts paid by the Partnership's Managing Partner. Information on the Managing Partner's principal accountant fees and services is set forth under the caption "Independent Public Auditors" in Apache's 2004 proxy statement.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES, AND REPORTS ON FORM 8-K

a. (1) Financial Statements - See accompanying index to financial statements in Item 8 above.

(2) Financial Statement Schedules - See accompanying index to financial statements in Item 8 above.

(3) Exhibits

3.1 Partnership Agreement of Apache Offshore Investment Partnership (incorporated by reference to Exhibit (3)(i) to Form 10 filed by Partnership with the Commission on April 30, 1985, Commission File No. 0-13546).

3.2 Amendment No. 1, dated February 11, 1994, to the Partnership Agreement of Apache Offshore Investment Partnership (incorporated by reference to Exhibit 3.3 to Partnership's Annual Report on Form 10-K for the year ended December 31, 1993, Commission File No. 0-13546).

3.3 Limited Partnership Agreement of Apache Offshore Petroleum Limited Partnership (incorporated by reference to Exhibit (3)(ii) to Form 10 filed by Partnership with the Commission on April 30, 1985, Commission File No. 0-13546).

10.1 Form of Assignment and Assumption Agreement between Apache Corporation and Apache Offshore Petroleum Limited Partnership (incorporated by reference to Exhibit 10.2 to Partnership's Quarterly Report on Form 10-Q for the quarter ended June 30, 1992, Commission File No. 0-13546).

10.2 Joint Venture Agreement, dated as of November 23, 1992, between Apache Corporation and Apache Offshore Petroleum Limited Partnership (incorporated by reference to Exhibit 10.6 to Partnership's Annual Report on Form 10-K for the year ended December 31, 1992, Commission File No. 0-13546).

10.3 Matagorda Island 681 Field Purchase and Sale Agreement with Option to Exchange, dated November 24, 1992, between Apache Corporation, Shell Offshore, Inc. and SOI Royalties, Inc. (incorporated by reference to Exhibit 10.7 to Partnership's Annual Report on Form 10-K for the year ended December 31, 1992, Commission File No. 0-13546).

*23.1 Consent of Ryder Scott Company, L.P., Petroleum Consultants.

*31.1 Certification of Chief Executive Officer.

*31.2 Certification of Chief Financial Officer.

*32.1 Certification of Chief Executive Officer and Chief Financial Officer.

99.1 Consent statement of the Partnership, dated January 7, 1994 (incorporated by reference to Exhibit 99.1 to Partnership's Annual Report on Form 10-K for the year ended December 31, 1993, Commission File No. 0-13546).

99.2 Proxy statement to be dated on or about March 31, 2004, relating to the 2004 annual meeting of stockholders of Apache Corporation (incorporated by reference to the document filed by Apache pursuant to Rule 14A, Commission File No. 1-4300).

*Filed herewith.

b. Reports filed on Form 8-K.

No reports on Form 8-K were filed during the fiscal quarter ended December 31, 2003.

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.

APACHE OFFSHORE INVESTMENT PARTNERSHIP

By: Apache Corporation, General Partner

Date: March 11, 2004

By: /s/ G. Steven Farris
G. Steven Farris
President, Chief Executive Officer and
Chief Operating Officer

POWER OF ATTORNEY

The officers and directors of Apache Corporation, General Partner of Apache Offshore Investment Partnership, whose signatures appear below, hereby constitute and appoint G. Steven Farris, Roger B. Plank, P. Anthony Lannie and Eric L. Harry, and each of them (with full power to each of them to act alone), the true and lawful attorney-in-fact to sign and execute, on behalf of the undersigned, any amendment(s) to this report and each of the undersigned does hereby ratify and confirm all that said attorneys shall do or cause to be done by virtue thereof.

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.

NAME	TITLE	DATE
/s/ G. Steven Farris G. Steven Farris	Director, President, Chief Executive Officer and Chief Operating Officer (Principal Executive Officer)	March 11, 2004
/s/ Roger B. Plank Roger B. Plank	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	March 11, 2004
/s/ Thomas L. Mitchell Thomas L. Mitchell	Vice President and Controller (Principal Accounting Officer)	March 11, 2004

NAME	TITLE	DATE
/s/ Raymond Plank Raymond Plank	Chairman of the Board	March 11, 2004
/s/ Frederick M. Bohen Frederick M. Bohen	Director	March 11, 2004
/s/ Randolph M. Ferlic Randolph M. Ferlic	Director	March 11, 2004
/s/ Eugene C. Fiedorek Eugene C. Fiedorek	Director	March 11, 2004
/s/ A. D. Frazier, Jr. A. D. Frazier, Jr.	Director	March 11, 2004
/s/ Patricia Albjerg Graham Patricia Albjerg Graham	Director	March 11, 2004
/s/ John A. Kocur John A. Kocur	Director	March 11, 2004
/s/ George D. Lawrence George D. Lawrence	Director	March 11, 2004
/s/ F. H. Merelli F. H. Merelli	Director	March 11, 2004
/s/ Rodman D. Patton Rodman D. Patton	Director	March 11, 2004
/s/ Charles J. Pitman Charles J. Pitman	Director	March 11, 2004
/s/ Jay A. Precourt Jay A. Precourt	Director	March 11, 2004

INDEX TO EXHIBITS

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99.2	Proxy statement to be dated on or about March 31, 2004, relating to the 2004 annual meeting of stockholders of Apache Corporation (incorporated by reference to the document filed by Apache pursuant to Rule 14A, Commission File No. 1-4300).

*Filed herewith.

EXHIBIT 23.1

[Letterhead of Ryder Scott Company, L.P.]

Consent of Ryder Scott Company, L.P.

As independent petroleum engineers, we hereby consent to the incorporation by reference in this Form 10-K of Apache Offshore Investment Partnership to our Firm's name and our Firm's review of the proved oil and gas reserve quantities of Apache Offshore Investment Partnership as of January 1, 2004.

/s/ Ryder Scott Company, L.P.
Ryder Scott Company, L.P.

Houston, Texas
March 10, 2004

EXHIBIT 31.1

CERTIFICATIONS

I, G. Steven Farris, certify that:

1. I have reviewed this annual report on Form 10-K of Apache Offshore Investment Partnership;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information ; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ G. Steven Farris

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G. Steven Farris
President, Chief Executive Officer and
Chief Operating Officer
of Apache Corporation, General Partner

Date: March 11, 2004

EXHIBIT 31.2

CERTIFICATIONS

I, Roger B. Plank, certify that:

1. I have reviewed this annual report on Form 10-K of Apache Offshore Investment Partnership;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information ; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ Roger B. Plank

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Roger B. Plank
Executive Vice President and Chief Financial Officer
of Apache Corporation, Managing Partner

Date: March 11, 2004

EXHIBIT 32.1

APACHE OFFSHORE INVESTMENT PARTNERSHIP

CERTIFICATION OF CHIEF EXECUTIVE OFFICER
AND CHIEF FINANCIAL OFFICER

I, G. Steven Farris, certify that the Annual Report of Apache Offshore Investment Partnership on Form 10-K for the year ended December 31, 2003, fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. ss.78m or ss.78o (d)) and that information contained in such report fairly represents, in all material respects, the financial condition and results of operations of Apache Offshore Investment Partnership.

/s/ G. Steven Farris

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By: G. Steven Farris
Title: President, Chief Executive Officer
and Chief Operating Officer of
Apache Corporation, Managing Partner

I, Roger B. Plank, certify that the Annual Report of Apache Offshore Investment Partnership on Form 10-K for the year ended December 31, 2003, fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. ss.78m or ss.78o (d)) and that information contained in such report fairly represents, in all material respects, the financial condition and results of operations of Apache Offshore Investment Partnership.

/s/ Roger B. Plank

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By: Roger B. Plank
Title: Executive Vice President
and Chief Financial Officer of
Apache Corporation, Managing Partner