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

Form 10-K/A
(Amendment No. 1)

☑ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the Fiscal Year Ended December 31, 2005

OR

o **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 if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act of 1933. Yes o No ☑

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes o No ☑

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

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

Indicate by check mark whether the Registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act
Large accelerated filer o Accelerated filer o Non-accelerated filer ☑

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act): Yes o No ☑

Aggregate market value of the voting and non-voting common equity held by non-affiliates of registrant as of June 30, 2005 $14,375,129

DOCUMENTS INCORPORATED BY REFERENCE:

Portions of Apache Corporation's proxy statement relating to its 2006 annual meeting of stockholders have been incorporated by reference into Part III hereof.

EXPLANATORY NOTE

We are filing this Amendment No. 1 to our Annual Report on Form 10-K for the year ended December 31, 2005 to respond to comments received by us from the Staff of the Securities and Exchange Commission ("SEC"). The only changes from the prior filing are in Part II, Item 9A and the dates of signatures and required certifications, including the addition of a date to Exhibit 32.1. Our consolidated financial position and consolidated results of operations for the periods presented have not been restated or changed in any manner from the consolidated financial position and consolidated results of operation originally reported.

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DESCRIPTION

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 Investment Partnership does not maintain a website, so we do not make electronic access to our reports filed with the Securities and Exchange Commission (SEC) available on or through a website. The Investment Partnership will, however, provide paper copies of these filings, free of charge, to anyone so requesting. Included in the Investment Partnership's annual reports on Form 10-K and quarterly reports on Form 10-Q are the certifications of the Managing Partners' chief executive officer and chief financial officer that are required by applicable laws and regulations. Any requests for copies of filing with the SEC should be made by mail to Apache Offshore Investment Partnership, 2000 Post Oak Blvd., Houston, Texas 77056, Attention: David Higgins, or by telephone at 713-296-6690.

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, 2005, 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.

2005 Results and Business Development

The Partnership reported net income in 2005 of $11.0 million, or $8,048 per Investing Partner Unit. Earnings were up $1.5 million from 2004 on the strength of higher oil and gas prices in 2005. Natural gas production averaged 3,172 Mcf per day in 2005, while oil sales averaged 203 barrels per day. Production added through drilling in 2005 partially offset declines from natural depletion.

During 2005, the Partnership participated in drilling three new wells at Ship Shoal 258/259. The Ship Shoal 259 JA-9 was completed as a producer in August, while the Ship Shoal 258 JB-7 was completed as a producer in late November. The Ship Shoal 259 JA-10 well was a dry hole. Also during 2005, the Partnership sold its interest in the South Pass 83 Field for $134,060. The purchaser also assumed all dismantlement and abandonment obligations for the property.

Since inception, the Partnership has acquired an interest in 49 prospects. As of December 31, 2005, 44 of those prospects have been surrendered or sold.

As of December 31, 2005, the Partnership had 52 producing wells on the Partnership's five remaining developed fields. Two of the Partnership's producing wells are dual completions. The Partnership had, at December 31, 2005, estimated proved oil and gas reserves of 8.4 Bcfe, of which 54 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 2005 was purchased largely by Plains Marketing LP 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. 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.

ITEM 1A. RISK FACTORS

The Partnership's business activities are subject to significant hazards and risks, including those described below. If any of such events should occur, the Partnership's business, financial condition, liquidity and/or results of operations could be materially harmed, and holders of the Partnership Units could lose part or all of their investments.

Partnership's Profitability is Highly Dependent on the Prices of Crude Oil, Natural Gas and Natural Gas Liquids, which have Historically been very Volatile

The Partnership's revenues, profitability, operating cash flows and future rate of growth are highly dependent on the prices of crude oil, natural gas and natural gas liquids, which are affected by numerous factors beyond its control. Historically these prices have been very volatile. A significant downward trend in commodity prices would have a material adverse effect on our revenues, profitability and cash flow and could result in a reduction in the carrying value of our oil and gas properties and the amounts of our proved oil and gas reserves.

Drilling Activities may not be Productive

Drilling for oil and gas involves numerous risks, including the risk that we will not encounter commercially productive oil or gas reservoirs. The costs of drilling, completing and operating wells are often uncertain, and drilling operations may be curtailed, delayed or canceled as a result of a variety of factors including, but not limited to:

- unexpected drilling conditions;
- pressure or irregularities in formations;
- equipment failures or accidents;
- fires, explosions, blow-outs and surface cratering;
- marine risks such as capsizing, collisions and hurricanes;
- other adverse weather conditions; and
- shortages or delays in the delivery of equipment.

Certain of the Partnership's future drilling activities may not be successful and, if unsuccessful, this failure could have an adverse effect on our future results of operations and financial condition.

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 against all operational risks.

Industry Competition

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 the Partnership's new independent auditors for 2002. Ernst & Young also served as the Partnership's independent auditors in 2003, 2004 and 2005. 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 the Partnership's financial statements relief that may be available to investors under the federal securities laws against auditing firms.

ITEM 1B. UNRESOLVED STAFF COMMENTS

As of the date of filing of this report, the Partnership had no material comments from the staff of the SEC that were unresolved for more than 180 days as of December 31, 2005.

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, 2005, is set forth below:

Lease Block	State	Developed Acreage	
		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
Ship Shoal 201, 202	LA	10,000	—
		61,061	3,157

At December 31, 2005, 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, 2005, is set forth below:

Lease Block	State	Gas		Oil	
		Gross	Net	Gross	Net
Ship Shoal 258, 259	LA	9	.57	–	–
South Timbalier 276, 295, 296	LA	1	.07	33	2.34
North Padre Island 969, 976	TX	4	.28	—	—
Matagorda Island 681, 682, 683	TX	3	.19	—	—
Ship Shoal 201, 202	LA	1	—	1	—
		18	1.11	34	2.34

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:

Year	Net Exploratory			Net Development		
	Productive	Dry	Total	Productive	Dry	Total
2005	—	—	—	.13	.06	.19
2004	—	—	—	.30	—	.30
2003	—	—	—	—	—	—

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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.

Year Ended December 31,	Production Oil (Mbbls)	Production Gas (MMcf)	Production NGLs (Mbbls)	Average Production Cost per Mcfe	Average Sales Prices Oil (per Bbl)	Average Sales Prices Gas (per Mcf)	Average Sales Prices NGLs (per Bbl)
2005	74	1,158	18	$.78	$53.91	$8.78	$33.98
2004	110	1,398	26	.48	40.62	6.23	26.84
2003	125	1,432	6	.42	30.73	5.56	23.92

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, 2005, the Partnership had total estimated proved reserves of 643,081 barrels of crude oil, condensate and NGLs and 4.5 Bcf of natural gas. Combined, these total estimated proved reserves are equivalent to 8.4 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, 2005, 2004 and 2003, changes in estimated 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 2005 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. Estimated 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 2005.

PART II

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

As of December 31, 2005, there were 1,053.4 of the Partnership’s Units outstanding held by 886 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 $9.5 million, or $9,000 per Unit, during 2005 and approximately $6.4 million, or $6,000 per Unit, during 2004.

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, 2005, 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 year 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 “Risk Factors Related to the Partnership’s Business and Operations”.

	As of or For the Year Ended December 31,				
	2005	2004	2003	2002	2001
	(In thousands, except per Unit amounts)				
Total assets	$ 11,624	$ 12,215	$ 11,674	$ 9,834	$ 9,413
Partners’ capital	$ 10,311	$ 11,293	$ 10,475	$ 9,610	$ 8,369
Oil and gas sales	$ 14,779	$ 13,874	$ 11,951	$ 6,868	$ 10,495
Net income	$ 11,048	$ 9,591	$ 8,037	$ 3,524	$ 7,264
Net income allocated to:					
Managing Partner	$ 2,555	$ 2,407	$ 2,037	$ 1,036	$ 1,731
Investing Partners	8,493	7,184	6,000	2,488	5,533
	$ 11,048	$ 9,591	$ 8,037	$ 3,524	$ 7,264
Net income per Investing Partner Unit	$ 8,048	$ 6,786	$ 5,598	$ 2,259	$ 4,922
Cash distributions per Investing Partner Unit	$ 9,000	$ 6,000	$ 4,500	$ 1,000	$ 4,000

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 2005. 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's oil and gas production has declined in each of the last two years and is expected to continue to decline with Partnership's limited capital expenditures.

Since all of the Partnership's properties are located in the Gulf of Mexico, its operations and cash flow can be significantly impacted by hurricanes and other inclement weather. These events may also have detrimental impact on third-party pipelines and processing facilities, which the Partnership relies upon to transport and process the crude oil and natural gas it produces. During the third quarter of 2005, four hurricanes struck the Gulf of Mexico that impacted the Partnership's operations. Two of these storms, Hurricanes Denis and Emily, only required temporary curtailment of production while the operators' personnel were evacuated for safety purposes. The other two storms, Hurricanes Katrina and Rita, caused lengthier production curtailments as the storms damaged third-party pipelines and disrupted the operations of crews which could assess and repair damage to the Partnership's or other's facilities. While the Partnership's platforms avoided major damage, the Partnership's production was curtailed approximately 22 percent during the third quarter of 2005 as a result of hurricanes. The Partnership's production was restored to pre-hurricane levels early in the fourth quarter.

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. During 2005, the Partnership participated in drilling three development wells at Ship Shoal 258/259, of which two wells were completed as producing gas wells and one well was dry. The Partnership currently anticipates that future development cost will largely be directed to recompletion projects in the Ship Shoal 258/259 and South Timbalier 295 fields.

Generally, the Partnership has used its remaining available cash to fund distributions to its Partners. Reflecting the significant impact of oil and gas prices on net income and cash from operating activities, distributions to Investing Partners increased to $9,000 per Unit in 2005, up 50 percent from 2004. Distributions to Investing Partners increased to $6,000 per Unit in 2004 from $4,500 in 2003.

Results of Operations

This section includes a discussion of the Partnership's 2005 and 2004 results of operations, and items contributing to changes in revenues and expenses during those periods.

Net Income and Revenue

The Partnership reported net income of $11.0 million for 2005, up 15 percent from 2004 on the strength of higher commodity prices. Net income per Investing Partner Unit increased in 2005 to $8,048, up from $6,786 in 2004. The Partnership reported earnings in 2004 of $9.6 million.

Total revenues increased to $14.9 million in 2005 on higher prices. Interest income earned by the Partnership on short-term cash investments in 2005 more than doubled from 2004 as a result of higher average investment balances and higher interest rates in 2005. Interest income in 2004 increased 44 percent from the prior year, increasing from $27,081 in 2003 to $39,087 in 2004.

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

	For the Year Ended December 31,		
	2005	2004	2003
Gas volumes — Mcf per day	3,172	3,820	3,924
Average gas price — per Mcf	$ 8.78	$ 6.23	$ 5.56
Oil volumes — barrels per day	203	301	342
Average oil price — per barrel	$53.91	$40.62	$30.73
NGL volumes — barrels per day	51	71	16
Average NGL price — per barrel	$33.98	$26.84	$23.92

The Partnership's revenues are sensitive to changes in prices received for its products. A substantial portion of the Partnership's production is sold at prevailing market prices, which fluctuate in response to many factors that are outside of our control. Imbalances in the supply and demand for oil and natural gas can have dramatic effects on the prices we receive for our production. Political instability and availability of alternative fuels could impact worldwide supply, while other economic factors could impact demand.

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 2005 totaled $10.2 million, up 17 percent from 2004 on higher prices. The Partnership's average realized natural gas price for 2005 improved 41 percent from 2004. The $2.55 per Mcf increase in gas price from a year ago boosted sales by approximately $3.6 million. Daily gas production for 2005 decreased 17 percent from 2004, decreasing sales by $2.1 million. The decline in production from 2004 reflected natural depletion, downtime for hurricanes, and the sale of Partnership's interest in the South Pass 83 Field in early 2005. The Partnership completed the Ship Shoal 259 JA-9 well in August and the Ship Shoal JB-7 in late November which partially mitigated the production decline from 2004.

Natural gas sales for 2004 totaled $8.7 million, up nine percent from 2003 on higher prices. The Partnership's average realized natural gas price for 2004 improved 12 percent from 2003. The $.67 per Mcf increase in gas price from a year ago boosted sales by approximately $1.0 million. Daily gas production for 2004 decreased three percent from 2003, decreasing sales by $.2 million. Production added through drilling successes at Ship Shoal 258/259 and recompletions at South Timbalier 295 and Ship Shoal 259 in 2004 partially offset natural depletion for the year. The Partnership completed the Ship Shoal 258 JB-6 well in mid-April, the Ship Shoal 259 JA-3 in late May, the Ship Shoal 259 JA-7 in late July and the Ship Shoal 258 JA-8 in late September.

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.

Crude Oil Sales

In 2005, the Partnerships crude oil sales totaled $4.0 million. A $13.29 per barrel, or 33 percent increase in the Partnership's average realized oil price in 2004 increased oil revenues by $.8 million from 2004. Oil production decreased 33 percent from 2004 as a result of production declines at South Timbalier 295 resulting from natural depletion.

The Partnership's crude oil sales in 2004 totaled $4.5 million, up 17 percent from 2003. A $9.89 per barrel, or 32 percent, increase in the Partnership's average realized oil price in 2004 increased oil revenues by $1.2 million from 2003. Oil production decreased 12 percent from 2003 as a result of declines at South Timbalier 295.

Operating Expenses

The Partnership's depreciation, depletion and amortization (DD&A) rate, expressed as a percentage of oil and gas sales, decreased to 14 percent in 2005. The decrease in DD&A rate as a percentage of sales reflected higher oil and gas prices in 2005. The lower DD&A in 2005 also reflected favorable reserve revisions at Ship Shoal 258/259 and proceeds from the sale of South Pass 83. The Partnership's DD&A rate, expressed as a percentage of oil and gas sales, decreased to 20 percent in 2004 from 24 percent in 2003 as a result of higher oil and gas prices in 2004. DD&A expense declined slightly in 2004 on an absolute basis as a result of the decline in the Partnership's production from 2004, and as a result of reserve additions from drilling at Ship Shoal 258/259.

Lease operating costs in 2005 increased approximately $241,000 from a year ago primarily as result of a workover on the North Padre Island 976 A-3 well, repairs on the North Padre 969/976 platform, repairs at South Pass 83 in January and painting platforms at Ship Shoal 258/259, Matagorda 681/682 and South Timbalier 295 in 2005. Air and marine transportation costs also increased LOE in 2005 with higher fuel costs. Administrative expense increased slightly from last year, increasing to $417,000 in 2005. The increase largely reflected higher auditing, tax and reservoir engineering fees in 2005.

Lease operating costs in 2004 increased approximately $100,000 from a year ago primarily as result of higher repair and maintenance costs. The increase also reflected generally higher service costs, chemical costs and fuel and power costs impacting all oil and gas producers. Repair cost in 2004 included cost to repair damage to the South Pass 83 platform resulting from Hurricane Ivan. Administrative expense declined slightly from last year, dropping to $403,000 in 2004.

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. In this case, the Partnership records sales at the price received from the purchaser which is net of transportation costs. 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. In this case, the Partnership records the transportation cost as gathering and transportation costs. The Partnership's treatment of transportation costs is pursuant to Emerging Issues Task Force Issue 00-10, "Accounting or Shipping and Handling Fees and Costs" and as a result a portion of our transporting costs are reflected in sales prices and a portion is reflected as Transportation and Gathering expense.

Capital Resources and Liquidity

The Partnership's primary capital resource is net cash provided by operating activities, which totaled $12.3 million for 2005. Benefiting from strong commodity prices throughout 2005, the Partnership's 2005 net cash provided by operating activities increased $.6 million, or 5 percent, from a year ago. Net cash provided by operating activities in 2004 increased 16 percent from 2003 on increases in both oil and gas production and 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 68 percent of the Partnership's 2005 production and 54 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 is projected to decline in the future.

Approximately 69 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 will have to be spent to access these reserves and that the estimated reserves from these projects are based on prices at December 31, 2005. The Partnership's liquidity may be negatively impacted if the actual quantity of reserves that are ultimately produced are materially different from current estimates. Also, if prices decline significantly from current levels, the Partnership may not be able to fund the necessary capital investment, or development of the remaining reserves may not be economical for the Partnership.

The Partnership may reduce capital expenditures or distributions to partners, or both, 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.

On an ongoing basis, the Partnership reviews the possible sale of lower value properties prior to incurring associated dismantlement and abandonment cost. During 2005, the Partnership sold its interest in the South Pass 83 field to a third party for $134,060. The purchaser also assumed all dismantlement and abandonment obligations for the property. The South Pass 83 field had insignificant levels of production at the time of the sale and the divestiture is not expected to materially impact future operating income.

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, 2005. The Partnership did not have any contractual obligations as of December 31, 2005, 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 2005, the Partnership's oil and gas property expenditures totaled $1.8 million, primarily related to the Partnership's participation in drilling three wells at Ship Shoal 258/259. During the year, the Partnership drilled the Ship Shoal 259 JA-9, Ship Shoal 258 JB-7 and Ship Shoal 259 JA-10 wells. The JA-9 and JB-7 wells were completed as producers in 2005, while the JA-10 well was a dry hole. The Partnership also participated in one recompletion project at South Timbalier 295 during 2005. During 2004, the Partnership's oil and gas property expenditures totaled $1.9 million. These additions related to the Partnership's participation in drilling four wells at Ship Shoal 258/259, a recompletion at South Timbalier 295 and a recompletion at Ship Shoal 259. During 2003, the partnership participated in nine recompletions at South Timbalier 295 and one recompletion at Ship Shoal 259. There were no new drilling wells in 2003 for the Partnership.

Based on preliminary information provided by the operators of the properties in which the Partnership owns interests, the Partnership anticipates capital expenditures will total less than $1 million in 2006. 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 2005, distributions of $9.5 million, or $9,000 per Unit, were paid to Investing Partners. Distributions of $6.4 million, or $6,000 per Unit, were made to Partners during 2004. Favorable oil and gas prices allowed for the increase in the per Unit distributions in 2005. 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 2005, the first right of presentment offer of $12,418 per Unit, plus interest to the date of payment, was made to Investing Partners based on a December 31, 2004 valuation date. The second right of presentment offer of $9,337 per Unit was made to the Investing Partners based a valuation date of June 30, 2005. As a result the Partnership acquired 2.3 units for a total of $22,776. In 2004 and 2003, Investing Partners were paid $55,881 and $295,734, respectively, for a total of 29.2 Units.

There will be two rights of presentment in 2006, 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.

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.

Critical Accounting Policies and Estimates

The following details the more significant accounting policies, estimates and judgments of the Partnership. 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 percent using commodity prices in effect at the end of the reporting period. If the full cost pool is in excess of the ceiling limitation, the excess amount is charged through income.

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. In addition, gains or losses on the sale or other disposition of oil and gas properties are not recognized. Unless the gain or loss would significantly alter the relationship between capitalized cost and the proved oil and gas reserves of the Company. 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. Generally, the application of the full-cost method of accounting for oil and gas property results in higher capitalized costs and higher depletion, depreciation and amortization rates compared to similar companies applying the successful efforts method of accounting.

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 depreciation, depletion and amortization (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 the 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. As such, beginning in 2003, the Partnership's depletion expense is reduced since it will deplete a discounted ARO rather than the undiscounted value previously depleted in our oil and gas property base. The lower depletion expense under SFAS No. 143 is offset, however, by accretion expense, which reflects increases in the discounted asset retirement obligation over time.

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.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT 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 2005, monthly oil price realizations ranged from a low of $45.04 per barrel to a high of $62.80 per barrel. Gas price realizations ranged from a monthly low of $5.85 per Mcf to a monthly high of $14.23 per Mcf during the same period. While remaining strong compared to historical levels, gas prices trended upward during most of 2005. Based on the Partnership's average daily production for 2005, a $1.00 per barrel change in the weighted average realized oil price would have increased or decreased revenues for the year by approximately $74,000 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 $115,788. The Partnership did not use derivative financial instruments or otherwise engage in hedging activities during the three-year period ended December 31, 2005. 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.

Governmental Risk

The Partnership's operations have been, and at times in the future may be, affected by political developments and by federal, state and local laws and regulations impacting production levels, taxes, environmental requirements and other assessments including a potential Windfall Profits Tax.

Weather and Climate Risk

Demand for oil and natural gas are, to a significant degree, dependent on weather and climate, which impacts the price the Partnership receives for the commodities it produces. In addition, production, development activities and equipment can be adversely affected by severe weather, such as hurricanes in the Gulf of Mexico.

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, capital expenditure projections, 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.

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ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

APACHE OFFSHORE INVESTMENT PARTNERSHIP
INDEX TO FINANCIAL STATEMENTS

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 REGISTERED PUBLIC ACCOUNTING FIRM

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, 2005 and 2004, 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, 2005. 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 the standards of the Public Company Accounting Oversight Board (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. We were not engaged to perform an audit of the Partnership's internal control over Financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Partnership's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our 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 and subsidiary at December 31, 2005 and 2004, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2005 in conformity with U.S. generally accepted accounting principles.

ERNST & YOUNG LLP

Houston, Texas
March 10, 2006

APACHE OFFSHORE INVESTMENT PARTNERSHIP
STATEMENT OF CONSOLIDATED INCOME

	For the Year Ended December 31, 2005	2004	2003
REVENUES:			
Oil and gas sales	$14,778,653	$13,873,998	$11,950,908
Interest income	99,970	39,087	27,081
Other revenue	—	—	14,567
	14,878,623	13,913,085	11,992,556
OPERATING EXPENSES:			
Depreciation, depletion and amortization	2,039,571	2,816,528	2,875,896
Asset retirement obligation accretion	45,672	48,744	37,605
Lease operating costs	1,159,366	918,337	818,636
Gathering and transportation expense	169,114	135,263	121,067
Administrative	417,000	403,000	405,000
	3,830,723	4,321,872	4,258,204
Operating income before cumulative effect of change in accounting principle	$11,047,900	$ 9,591,213	$ 7,734,352
Cumulative effect of change in accounting principle	—	—	302,407
NET INCOME	$11,047,900	$ 9,591,213	$ 8,036,759
NET INCOME ALLOCATED TO:			
Managing Partner	$ 2,554,528	$ 2,407,360	$ 2,036,681
Investing Partners	8,493,372	7,183,853	6,000,078
	$11,047,900	$ 9,591,213	$ 8,036,759
NET INCOME PER INVESTING PARTNER UNIT	$ 8,048	$ 6,786	$ 5,598
WEIGHTED AVERAGE INVESTING PARTNER UNITS OUTSTANDING	1,055.4	1,058.6	1,071.9

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, 2005	2004	2003
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$ 11,047,900	$ 9,591,213	$ 8,036,759
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	2,039,571	2,816,528	2,875,896
Asset retirement obligation accretion	45,672	48,744	37,605
Cumulative effect of change in accounting principle	—	—	(302,407)
Dismantlement and abandonment cost	(167,767)	(323,966)	(254,134)
Changes in operating assets and liabilities:			
(Increase) decrease in accrued revenues receivable	(470,419)	(324,111)	(26,046)
Increase (decrease) in accrued operating expenses	(3,204)	11,693	3,598
Increase (decrease) in receivable from Apache Corporation	(191,796)	(79,257)	(210,169)
Net cash provided by operating activities	12,299,957	11,740,844	10,161,102
CASH FLOWS FROM INVESTING ACTIVITIES:			
Additions to oil and gas properties	(1,678,072)	(1,570,794)	(1,916,566)
Increase (decrease) in accrued development costs	551,324	(334,740)	282,927
Proceeds from sales of oil and gas properties	134,060	—	—
Net cash used in investing activities	(992,688)	(1,905,534)	(1,633,639)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Repurchase of Partnership Units	(22,775)	(55,881)	(295,734)
Distributions to Investing Partners	(9,499,617)	(6,350,335)	(4,789,313)
Distributions to Managing Partner	(2,506,864)	(2,366,949)	(2,086,812)
Net cash used in financing activities	(12,029,256)	(8,773,165)	(7,171,859)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(721,987)	1,062,145	1,355,604
CASH AND CASH EQUIVALENTS, BEGINNING OF YEAR	3,333,640	2,271,495	915,891
CASH AND CASH EQUIVALENTS, END OF YEAR	$ 2,611,653	$ 3,333,640	$ 2,271,495

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

APACHE OFFSHORE INVESTMENT PARTNERSHIP
CONSOLIDATED BALANCE SHEET

	December 31, 2005	December 31, 2004
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 2,611,653	$ 3,333,640
Accrued revenues receivable	1,435,740	965,321
Receivable from Apache Corporation	357,270	165,474
	4,404,663	4,464,435
OIL AND GAS PROPERTIES, on the basis of full cost accounting:		
Proved properties	185,573,656	184,065,602
Less — Accumulated depreciation, depletion and amortization	(178,354,788)	(176,315,217)
	7,218,868	7,750,385
	$ 11,623,531	$ 12,214,820
LIABILITIES AND PARTNERS' CAPITAL		
CURRENT LIABILITIES:		
Accrued development costs	$ 551,324	$ —
Accrued operating expenses	60,565	63,769
	611,889	63,769
COMMITMENTS AND CONTINGENCIES (Note 7)		
ASSET RETIREMENT OBLIGATION	700,154	858,207
PARTNERS' CAPITAL:		
Managing Partner	255,285	207,621
Investing Partners (1,053.4 and 1,055.7 Units outstanding, respectively)	10,056,203	11,085,223
	10,311,488	11,292,844
	$ 11,623,531	$ 12,214,820

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, 2002	$ 217,341	$ 9,392,555	$ 9,609,896
Distributions	(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
Distributions	(2,366,949)	(6,350,335)	(8,717,284)
Repurchase of Partnership Units	—	(55,881)	(55,881)
Net income	2,407,360	7,183,853	9,591,213
BALANCE, DECEMBER 31, 2004	207,621	11,085,223	11,292,844
Distributions	(2,506,864)	(9,499,617)	(12,006,481)
Repurchase of Partnership Units	—	(22,775)	(22,775)
Net income	2,554,528	8,493,372	11,047,900
BALANCE, DECEMBER 31, 2005	$ 255,285	$ 10,056,203	$ 10,311,488

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

APACHE OFFSHORE INVESTMENT PARTNERSHIP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(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 1,053.4 Investing Partner Units (Units) outstanding at December 31, 2005. 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, 44 of those prospects have been surrendered/sold). The Partnership's working interests in the five remaining venture prospects range from 6.29 percent to 7.08 percent. As of December 31, 2005, the Partnership held a remaining interest in 10 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 68 percent of the Partnership's 2005 production and 54 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.

APACHE OFFSHORE INVESTMENT PARTNERSHIP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

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. In 2005, the first right of presentment offer of $12,418 per Unit, plus interest to the date of payment, was made to Investing Partners based on a December 31, 2004 valuation date. The second right of presentment offer of $9,337 per Unit was made to the Investing Partners based a valuation date of June 30, 2005. As a result the Partnership acquired 2.3 units for a total of $22,775. In 2004 and 2003, Investing Partners were paid $55,881 and $295,734, respectively, for a total of 29.2 Units.

The Partnership is not in a position to predict how many Units will be presented for repurchase during 2006, 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, 2002	$13,612,220	$12,047
June 30, 2003	14,345,895	9,512
December 31, 2003	14,338,941	11,518
June 30, 2004	13,730,918	8,988
December 31, 2004	17,331,746	12,418
June 30, 2005	15,131,715	9,337

	2005	2004	2003
Investing Partner Units Outstanding:			
Balance, beginning of year	1,055.7	1,060.7	1,084.9
Repurchase of Partnership Units	(2.3)	(5.0)	(24.2)
Balance, end of year	1,053.4	1,055.7	1,060.7

Capital Contributions —

A total of $85,000 per Unit, or approximately 57 percent, of investor subscription had been called through December 31, 2005. 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 1,053.4 Units at December 31, 2005.

(2) SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Statement Presentation —

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. Beginning in 2003, the Partnership changed its method of accounting for dismantlement, restoration and abandonment cost as described in Note 8. The Partnership now includes the present value of its dismantlement, restoration and abandonment costs within the capitalized oil and gas property balance and, therefore, no longer reflects the recognized abandonment obligations within the future development costs added to the amortizable base.

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.

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, 2005 and 2004, 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, 2005, 2004 and 2003.

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 Apache —

The receivable from 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.

APACHE OFFSHORE INVESTMENT PARTNERSHIP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Shipping and Handling Costs —

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.

(3) 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,		
		2005	2004	2003
			(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	$ 334	$ 322	$ 324
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	$ 71	$ 71	$ 86

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.

APACHE OFFSHORE INVESTMENT PARTNERSHIP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

(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.

	2005	2004 (In thousands)	2003
Oil and Gas Properties			
Balance, beginning of year	$ 184,066	$ 182,174	$ 179,657
Costs incurred during the year:			
Development —			
Investing Partners	1,766	1,841	2,154
Managing Partner	44	51	37
Asset retirement cost from adoption of SFAS No. 143 —			
Investing Partners	—	—	323
Managing Partner	—	—	3
Property sales —			
Investing Partners	(274)	—	—
Managing Partners	(28)	—	—
Balance, end of year	$ 185,574	$ 184,066	$ 182,174

	Managing Partner	Investing Partners (In thousands)	Total
Accumulated Depreciation, Depletion and Amortization			
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
Provision	75	2,741	2,816
Balance, December 31, 2004	20,840	155,475	176,315
Provision	52	1,988	2,040
Balance, December 31, 2005	$ 20,892	$ 157,463	$ 178,355

The Partnership's aggregate DD&A expense as a percentage of oil and gas sales for 2005, 2004 and 2003 was 14 percent, 20 percent and 24 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 accounted for 37 percent of the Partnership's oil and gas sales in 2003. 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.

Sales to Plains Marketing LP accounted for 26 percent and 32 percent of the Partnership's oil and gas sales in 2005 and 2004, respectively, while sales to Morgan Stanley Capital Group accounted for 10 percent of 2005 oil and gas sales. Sales to Chevron Texaco accounted for 32 percent of the Partnership's oil and gas sales in 2003.

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 of $15,185 in 2005. The Partnership paid the Apache subsidiary transportation fees totaling $31,008 in 2004 and $43,606 in 2003 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, 2005 and 2004 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, 2005.

(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) ASSET RETIREMENT OBLIGATION

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 and recorded an increase to net oil and gas properties of $1.1 million and associated 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.

The following table is a reconciliation of the asset retirement obligation liability:

	2005	2004
Asset retirement obligation at beginning of period	$ 858,207	$ 812,520
Liabilities incurred	167,767	—
Liabilities settled	(336,100)	(6,101)
Accretion expense	45,672	48,744
Revisions in estimated liabilities	(35,392)	3,044
Asset retirement obligation at December 31	$ 700,154	$ 858,207

Liabilities settled in 2005 included $168,333 related to the Partnership's sale of its interest in the South Pass 83 Field.

(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.

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(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:

	2005	2004	2003
Net partnership ordinary income for federal income tax reporting purposes	$11,103,205	$ 9,993,343	$ 7,846,759
Plus: Items of current (income) expense for tax reporting purposes only —			
Intangible drilling cost	1,318,588	1,457,967	1,358,245
Dismantlement and abandonment cost	167,767	6,101	575,553
Gain on sale of properties	(134,060)	—	—
Tax depreciation	677,643	999,074	867,296
	2,029,938	2,463,142	2,801,094
Less: full cost DD&A expense	(2,039,571)	(2,816,528)	(2,875,896)
Less: asset retirement obligation accretion	(45,672)	(48,744)	(37,605)
Plus: cumulative effect of change in accounting principle	—	—	302,407
Net income	$11,047,900	$ 9,591,213	$ 8,036,759

The Partnership's tax bases in net oil and gas properties at December 31, 2005 and 2004 was $4,168,176 and $4,351,881, 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, 2005 and 2004.

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,	
	2005	2004
Liabilities for federal income tax purposes	$ 611,889	$ 63,769
Asset retirement liability	700,154	858,207
Liabilities under accounting principles generally accepted in the United States	$1,312,043	$921,976

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

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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)

	2005		2004		2003	
	Oil	Gas	Oil	Gas	Oil	Gas
Proved Reserves						
Beginning of year	648	5,244	618	5,992	849	6,339
Extensions, discoveries and other additions	4	147	32	1,027	12	161
Revisions of previous estimates	83	305	134	(377)	(112)	924
Production	(92)	(1,158)	(136)	(1,398)	(131)	(1,432)
End of year	643	4,538	648	5,244	618	5,992
Proved Developed						
Beginning of year	648	5,140	618	5,883	849	6,230
End of year	643	4,433	648	5,140	618	5,883

Oil includes crude oil, condensate and natural gas liquids.

Approximately 69 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 will 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.

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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,		
	2005	2004	2003
		(In thousands)	
Future cash inflows	$ 79,709	$ 58,854	$ 55,014
Future production costs	(7,962)	(5,943)	(5,645)
Future development costs	(3,485)	(3,571)	(3,789)
Net cash flows	68,262	49,340	45,580
10 percent annual discount rate	(26,666)	(17,590)	(14,995)
Discounted future net cash flows	$ 41,596	$ 31,750	$ 30,585

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

	For the Year Ended December 31,		
	2005	2004	2003
		(In thousands)	
Sales, net of production costs	$ (13,451)	$ (12,820)	$ (11,011)
Net change in prices and production costs	15,482	4,435	3,731
Extensions, discoveries and other additions	1,616	6,331	1,247
Development costs incurred	65	233	490
Revisions of quantities	4,391	1,644	813
Accretion of discount	3,175	3,059	3,083
Changes in future development costs	(126)	—	—
Changes in production rates and other	(1,306)	(1,717)	1,407
	$ 9,846	$ 1,165	$ (240)

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)				
2005					
Revenues	$ 3,398	$ 3,366	$ 3,154	$ 4,961	$ 14,879
Expenses	1,037	899	944	951	3,831
Net income	$ 2,361	$ 2,467	$ 2,210	$ 4,010	$ 11,048
Net income allocated to:					
Managing Partner	$ 568	$ 571	$ 515	$ 901	$ 2,555
Investing Partners	1,793	1,896	1,695	3,109	8,493
	$ 2,361	$ 2,467	$ 2,210	$ 4,010	$ 11,048
Net income per Investing Partner Unit (1)	$ 1,698	$ 1,797	$ 1,606	$ 2,947	$ 8,048
2004					
Revenues	$ 3,257	$ 3,180	$ 3,454	$ 4,022	$ 13,913
Expenses	1,037	1,052	1,098	1,135	4,322
Net income	$ 2,220	$ 2,128	$ 2,356	$ 2,887	$ 9,591
Net income allocated to:					
Managing Partner	$ 564	$ 545	$ 604	$ 694	$ 2,407
Investing Partners	1,656	1,583	1,752	2,193	7,184
	$ 2,220	$ 2,128	$ 2,356	$ 2,887	$ 9,591
Net income per Investing Partner Unit (1)	$ 1,561	$ 1,494	$ 1,657	$ 2,075	$ 6,786

(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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Disclosure Control 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 changes in the Partnership's internal controls over financial reporting during the fiscal quarter ending December 31, 2005 that have materially affected, or are reasonably likely to materially affect, the Partnership's internal control over financial reporting.

Report on Internal Control Over Financial Reporting

On February 24, 2004, the SEC approved an extension of the original compliance dates related to the internal control reporting pursuant to Section 404 of the Sarbanes-Oxley Act of 2002, as they pertain to companies with less than $75 million in market value of outstanding securities. The effective date for these non-accelerated filers was extended until fiscal years ending on or after July 15, 2005. On March 2, 2005, the SEC further extended the compliance date for non-accelerated filers until fiscal years ending on or after July 15, 2006. In September 2005, the SEC further extended the compliance date for U.S. non-accelerated filers until fiscal years ending on or after July 15, 2007. The Partnership has not issued a report on its internal control over financial reporting, nor had an assessment made by its independent registered public accounting firm, as they were not required for the years ended December 31, 2004 or 2005.

ITEM 9B. OTHER INFORMATION

None.

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 2006 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 (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 Apache’s website at http://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 Apache’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 Grants 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, 2005. Directors and officers of Apache own four Units, less than one percent of the Partnership’s Units, as of December 31, 2005. 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 5.0 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 Accountants” in Apache’s 2006 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 (incorporated by reference to Exhibit 23.1 to Partnership's Annual Report on Form 10-K for the year ended December 31, 2005, Commission File No. 0-13546)

*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 27, 2006, relating to the 2006 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).

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* Filed herewith.

b. Reports filed on Form 8-K.

No reports on Form 8-K were filed during the fiscal quarter ended December 31, 2005.

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: October 11, 2006

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

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

Name	Title	Date
/s/ G. Steven Farris G. Steven Farris	Director, President, Chief Executive Officer and Chief Operating Officer (Principal Executive Officer)	October 11, 2006
/s/ Roger B. Plank Roger B. Plank	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	October 11, 2006
/s/ Thomas L. Mitchell Thomas L. Mitchell	Vice President and Controller (Principal Accounting Officer)	October 11, 2006

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Name	Title	Date
* Raymond Plank	Chairman of the Board	October 11, 2006
* Frederick M. Bohen	Director	October 11, 2006
* Randolph M. Ferlic	Director	October 11, 2006
* Eugene C. Fiedorek	Director	October 11, 2006
* A. D. Frazier, Jr.	Director	October 11, 2006
* Patricia Albjerg Graham	Director	October 11, 2006
* John A. Kocur	Director	October 11, 2006
* George D. Lawrence	Director	October 11, 2006
* F. H. Merelli	Director	October 11, 2006
* Rodman D. Patton	Director	October 11, 2006
* Charles J. Pitman	Director	October 11, 2006
* Jay A. Precourt	Director	October 11, 2006

* By: /s/ Roger B. Plank
Roger B. Plank
Attorney in Fact
October 11, 2006

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* Filed herewith.

b. Reports filed on Form 8-K.

No reports on Form 8-K were filed during the fiscal quarter ended December 31, 2005.

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

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

Date: October 11, 2006

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

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

Date: October 11, 2006

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, 2005, fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. §78m or §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

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

Date: October 11, 2006

I, Roger B. Plank, certify that the Annual Report of Apache Offshore Investment Partnership on Form 10-K for the year ended December 31, 2005, fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. §78m or §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

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

Date: October 11, 2006