Formerly known as El Paso Energy Partners, L.P.

GulfTerra

GulfTerra Energy Partners, L.P. Four Greenway Plaza Houston, Texas 77046 www.gulfterra.com



Selected Highlights

Investment Performance	2002	2001	2000	1999	1998
Distributions per Unit (1) First Quarter Second Quarter Third Quarter Fourth Quarter	\$ 0.625 0.650 0.650 0.675	\$ 0.550 0.575 0.575 0.613	\$ 0.525 0.538 0.538 0.550	\$ 0.525 0.525 0.525 0.525	\$ 0.500 0.525 0.525 0.525
	\$ 2.600	\$ 2.313	\$ 2.150	\$ 2.100	\$ 2.075
Distribution at Year-End	\$ 2.70	\$ 2.45	\$ 2.20	\$ 2.10	\$ 2.10
Common Unit Price (1) High Low Year-End Close	\$ 38.68 20.50 27.84	25.50	\$ 28.00 18.13 27.44	\$ 25.13 16.75 19.00	\$ 28.50 19.75 20.13
Distribution Increase	10.2%	11.4%	4.8%	-	10.5%
Average Yield	7.8%	6.8%	9.2%	9.4%	8.6%
Total Annual Return (2)	-19.1%	44.9%	58.6%	3.4%	-29.2%
Financial Performance					
(In millions)					
Net Income	\$ 97.7	\$ 55.1	\$ 20.5	\$ 18.8	\$ 0.7
Net Income (Loss) per Common Unit	\$ 0.92	\$ 0.38	\$ (0.03)	\$ (0.34)	\$ 0.02
Cash Flows from Operating Activities	\$ 176.0	\$ 87.4	\$ 48.4	\$ 50.8	\$ 25.7
EBITDA ⁽³⁾	\$ 266.9	\$ 161.3	\$ 107.0	\$ 91.3	\$ 52.3
Total Capital Expenditures	\$ 1,768.2	\$ 589.0	\$ 303.8	\$ 149.0	\$ 66.1
Total Assets	\$ 3,130.9	\$ 1,357.4	\$ 869.5	\$ 583.6	\$ 442.7
Total Debt	\$ 1,906.3	\$ 820.0	\$ 538.0	\$ 465.0	\$ 338.0
Total Partners' Capital	\$ 949.9	\$ 500.7	\$ 311.1	\$ 96.5	\$ 82.9
Debt to Total Capitalization	67%	62%	63%	83%	80%
Fixed Charge Coverage	1.02x	1.07x	0.84x	0.89x	0.62x
Weighted Average Common Units Outstanding	42.8	34.4	29.1	25.9	24.4

Notes:

- (1) Effective at the close of business on August 5, 1998, the holders of approximately 94 percent of the 18.1 million Preference Units then outstanding converted those Preference Units into Common Units. Trading commenced for the Common Units on the NYSE on August 6, 1998. Prior to such date, there was no active trading market for the Common Units.
- (2) The Total Annual Return calculation assumes immediate reinvestment of distributions.
- (3) We use EBITDA because we believe it is a useful measure of our operating performance exclusive of financing costs and taxes, which are not relevant to operational efficiency. EBITDA is a non-GAAP measure and should not be considered as a substitute for GAAP measures such as cash flows from operating activities or net income. Our calculation of EBITDA may differ from similarly titled measurements used by other companies. A reconciliation of EBITDA to cash flows from operating activities is provided on our Web site at www.gulfterra.com in the For Investors section.

Terms we use in our annual report:

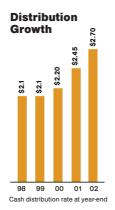
MBbls (/d): thousand barrels (per day)
MMBbls (/d): million barrels (per day)
Mcf (/d): thousand cubic feet of gas (per day)
MMcf (/d): million cubic feet of gas (per day)

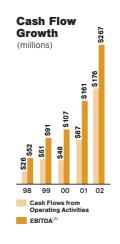
Bcf (/d): billion cubic feet of gas (per day)
MDth (/d): thousand dekatherms (per day)
MMDth (/d): million dekatherms (per day)

NGLs (/d): natural gas liquids (per day)
CAGR: compounded annual growth rate

EBITDA: earnings before interest, taxes, depreciation, and amortization; a reconciliation to cash flows from operating activities is available on our Web site at www.gulfterra.com **GAAP:** generally accepted accounting principles

Net Income Growth (millions) 98 99 90 01 02





Letter to Unitholders

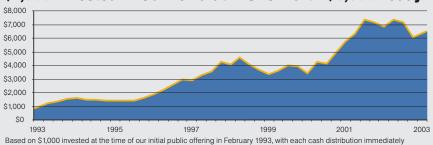
JulfTerra Energy Partners experienced another break-out year in 2002 with record EBITDA of \$267 million and net income of almost \$100 million. We continued to build on our strong platform of great assets, experienced and dedicated people, and a world-class opportunity set to become a leader in the midstream sector of the energy industry.

The Partnership's strong increases in EBITDA and cash flows from operating activities over the past five years (in excess of 50 percent and 60 percent compounded annual growth rate, respectively) have allowed us to deliver consistent increases in cash distributions to our unitholders as well as substantial capital appreciation on their investment. To continue this trend, we strive to grow by investing our capital to achieve above-average industry returns while maintaining a relatively low risk profile, which is consistent with diversified, fee-based midstream businesses and assets.

The success of our growth strategy since 1998, the year El Paso Corporation assumed management of the Partnership, illustrates both our disciplined approach to acquiring high-quality midstream assets that are strategically located in North America's most prolific supply regions as well as our reputation as a strong operator, committed service provider, and innovative developer of new infrastructure projects. This combination of







focused strategy and effective execution, when coupled with our strengthened balance sheet and financial capabilities, makes GulfTerra Energy Partners one of the leading MLPs in the market.

reinvested in partnership units

Some of our many achievements in 2002 include: the acquisition of El Paso Corporation's San Juan Basin gathering system and processing and treating assets, the acquisition of El Paso's Texas and Permian basin midstream assets, the completion of a major expansion at our Petal natural gas storage facility, and the announcement of new pipeline and platform projects to serve the growing Deepwater Trend of the Gulf of Mexico such as our Marco Polo, Cameron Highway, Phoenix, and Falcon projects. These assets and opportunities set the stage for strong performance over the next few years.

Vitally important to the success of GulfTerra is our dedicated team of employees. Our skilled management team and talented

operating personnel under the supervision of GulfTerra's experienced and independent board of directors have catapulted the Partnership's business to the next level. Our operations have been recognized with safety awards in the Gulf of Mexico, customer service awards in the San Juan Basin, and pipeline safety commendations from pipeline regulators in Texas. Our unitholders can expect the combined efforts of the Partnership's staff of energy professionals to continue building GulfTerra Energy Partners in the coming years.

During the past year, our many successes were overshadowed by turmoil in the energy industry and the events surrounding the owner of our general partner. With El Paso Corporation's strong support, we have moved quickly to institute a number of steps designed to further position GulfTerra as a stand-alone entity. In the area of corporate governance, in early 2003 we complied with recent New York Stock Exchange

guidelines requiring board independence and announced the intention to further increase the number of independent directors. We also announced the designation of a "financial expert," and we formed a governance and compensation committee of the board to oversee the management of the Partnership's assets. Concerning our business relationship with El Paso Corporation and its affiliates, we have reduced the level of related-party activity; made arrangements for the continual provision of employees, overhead, and administrative services to the Partnership; and improved the legal structure of the general partner.

As we mark our 10-year anniversary as a publicly traded master limited partnership, GulfTerra has become a major force in the midstream industry with a sustainable business model supported by strong industry fundamentals. From offshore platforms to onshore pipelines and storage operations to our natural gas liquids business, GulfTerra Energy Partners has the assets, people, and the opportunities to continue its proven record of extraordinary performance in the midstream.

PhtaPhym

Robert G. Phillips
Chief Executive Officer

Assets

he diversity of GulfTerra Energy Partners' midstream assets is our greatest strength. With the completion of the Texas, Permian, and San Juan acquisitions and our growing Gulf of Mexico business, we have assembled a world-class set of assets with size and scope. Our gathering, processing, treating, transportation, fractionation, platform, and storage assets hold leadership positions in each of the markets we serve, providing us with stable cash flows, optimization opportunities, and expansion potential.



Rattlesnake Plant
Acquired in November 2002,
our 58-MMcf/d Rattlesnake
treating plant removes
CO₂ from coal seam gas
for producers in the
San Juan Basin.



Petal Gas Storage GulfTerra offers high deliverabilty storage services from 13 Bcf of gross capacity to power plant operators and utilities located in the eastern United States.





Global Compression Project

40,000 hp of compression was installed in 1997 to lower wellhead pressures, allowing our producers to enhance production to 1.1 Bcf/d from more than 9,000 producing wells in the San Juan Basin.

GulfTerra Energy Partners is well positioned to benefit from today's strong natural gas fundamentals, including growing U.S. demand for natural gas and increased drilling activity by producers supported by strong energy prices. Our assets are located in some of the fastest growing supply basins in North America such as the Deepwater Trend of the Gulf of Mexico, the deep natural gas development plays in South Texas, and the Barnett Shale of North Texas. Additionally, the San Juan and Permian basins of New Mexico and the Black Warrior Basin in Alabama hold large, undeveloped natural gas resources and provide steady production volumes for our assets with solid long-term growth potential.

In addition to our geographic footprint, GulfTerra Energy Partners benefits from the functional diversity

and the integrated nature of our midstream operations. Our unique strategy is to offer a range of field and market services from gathering and processing in the San Juan Basin, to NGL fractionation and delivery to refinery and petrochemical markets in South Texas, to high deliverability gas storage at Petal for power plants and utilities in the Southeast. This gives GulfTerra a competitive advantage and reduces our dependence on single assets, geographic regions, and lines of business to meet our performance goals.

GulfTerra Energy Partners has set the stage for optimal growth in the future. While we will continue to look for conservative, accretive midstream acquisitions, our principal goals moving forward will be to integrate last year's acquisitions and complete our Gulf of Mexico projects. By realizing the operational synergies of these new assets, developing highreturn internal growth projects, and achieving additional cost savings across the company, we expect to deliver another record year of performance to our unitholders, with EBITDA expected to exceed \$420 million and cash flows from operating activities expected to be \$300 million.



Carlsbad Meter Station
Combined with our Indian Basin processing plant, the Carlsbad gathering system has been a steady performer as producers drill deeper in the Permian Basin.

1994 1992 1993 1995 02/1993 08/1995 IPO Leviathan Gas Pipeline Partners Began pipe lay of 10.5 million units at \$10.25 Poseidon Oil Pipeline 11/1993 Cash distribution per unit: \$1.10 Distribution Total assets:\$107 million 12/1992 ÖSEIDON increased to *number of units, unit price, Leviathan Gas Pipeline OIL PIPELINE COMPANY LLC \$1.20 and distributions are adjusted for Company formed 2 for 1 split in 1997 11/1994 Initiated service on 8 Viosca Knoll gas 08/1993 viathan gathering system Acquired Ship Shoal 50% ownership

332 platform

Falcon Nest Platform

Installed in the western Gulf of Mexico, our newest offshore platform processes more than 175 MMcf/d of gas from Pioneer Natural Resources Company discoveries from the Deepwater area.



Manzanares Compression

The largest of our San Juan global compression sites, we are increasing production from Burlington Resources, Conoco/Phillips, BP, and others through our 5,300-mile gathering system.







Waha Treater Located in West Texas, our gathering and treating facilities offer field services for producers in the Permian Basin who provide critical supplies to western and central United States natural gas markets.



1996 1997



04/1996 Poseidon Oil Pipeline System Phase I placed into service





04/1996 Initial production at Garden Banks 72 platform







12/1996

in service

Poseidon Phase II







04/1997

Distribution

increased

to \$1.70





12/1997 Poseidon Phase III and Viosca Knoll expansion in service

key element of GulfTerra Energy Partners' ongoing success has been the expertise and industry knowledge of the energy professionals who carry out the Partnership's diversified operations every day. The dedication and experience of our board of directors, executive management, and operating team have been critical to the results we have achieved since we began managing the Partnership in 1998.

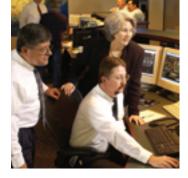
North Texas 36
As a part of our Pipeline
Integrity program, GulfTerra
Energy Partners utilizes
new, state-of-the-art
equipment such as the
Laser Pipeline Inspection
Tool for the assessment
of corrosion anomalies.





Control Center

Located in San Antonio, Texas. our state-of-the-art natural gas control center combines GulfTerra's wellhead automated telemetry technology with our StarWeb scheduling system to efficiently manage our pipeline systems.





Channel Pipeline Part of our EPGT Texas Pipeline System, the Channel System provides supplies to industrial customers located in the Houston Ship Channel area.

GulfTerra Energy Partners' independent board of directors continues to ensure that the Partnership's business model is successfully executed. Our company has taken a series of actions to strengthen the Partnership's governance structure and to ensure investor confidence in our business plan. Experts in the energy industry, each of our directors is engaged in the management of our growth plan and is committed to the highest level of integrity in the conduct of our business.

Over the last five years, our achievements have been spearheaded by our executive management team. Each member of our management team is a veteran of the midstream industry and brings a strong level of credibility to the Partnership's business activities. Our executives

at East Cameron

373 platform

have extensive experience in managing public companies, financing growth businesses, and meeting the stringent regulatory requirements of the oil and gas industry. Collectively, GulfTerra's management team has the commercial, legal, operations, engineering, and regulatory background to successfully steer the Partnership through the challenges of the energy industry.

GulfTerra Energy Partners also has the most talented operating personnel in the industry. As employees of El Paso Corporation, which owns our general partner, these professionals are under contract to operate our diverse assets, and they do an exceptional job. Our operating team was recognized in 2002 for safety performance, customer service in the field, and leadership in the development of state-of-the-art

pipeline integrity practices. As evidence of our dedication to excellence in operations, in 2002 we developed the "Team Midstream" customer service program. Each employee is meeting the challenge of a competitive world through customer service training and commitment.

Our board of directors, management team, and operating professionals are the backbone of GulfTerra Energy Partners and integral to our strategic business plan. We are motivated to help the Partnership achieve its overall business objectives and deliver outstanding results to our investors in the years ahead.

East Breaks

gathering system



Fast Breaks

"El Paso Energy Partners has been a great partner to work with on the Falcon project. I appreciate the cooperative efforts of EPN's management and operations teams that were essential in getting this project on stream, under budget, and ahead of schedule. We look forward to a strong relationship with EPN as we continue our success in this area."

> Scott D. Sheffield **Chairman and CEO Pioneer Natural Resources Company** April 2003

Customer Bill of Rights

Customers have the right to expect:

- Their calls to be returned promptly
- To be heard AND understood
- Answers to their questions
- Professional and courteous service
- To be treated with respect
- Services delivered as promised
- Timely and accurate service

Team Midstream Initiative

In the fall of 2002, we began an intensive customer service program to increase our effectiveness and efficiencies with our customers.



Chaco Plant

Our field and plant technicians and operations professionals are dedicated to safe, efficient operations while maintaining compliance with stringent environmental regulations.



Bob Phillips with Tim Baumgart, BP

In 2002, our San Juan operations team received BP's "Great Operator" Award for improvement in new well connection practices resulting in enhanced production schedules.





Garden Banks 72

In 2001, our operations team received the "Outstanding Operator of the Year" Award for operations of our Garden Banks 72 platform from the Lafayette, LA division of the Minerals Management Services.

2001



natural gas

storage

assets





Purchased remaining 1% of Viosca Knoll system



02/2001 Acquired EPN Texas NGL transportation and fractionation



07/2001 Prince Tension Lea Platform installed



10/2001 Acauired Chaco plant and remaining 50% interest in HIOS and East Breaks

01/2002 Acquired Anse

2002

La Butte and Hattiesburg NGL storage facilities





04/2002

Purchased Texas and New Mexico midstream assets

Sold Prince TLP and field interest

04/2002

Distribution increased to \$2.60

11/2002 Acquired San

Juan assets

10/2002 Distribution increased to \$2.70

12 /2002 44 million units outstanding at \$27.84 Cash distribution per unit: \$2.70 Total assets: \$3.1 billion

13

2002, GulfTerra Energy Partners executed agreements for almost \$900 million of new projects to serve new oil and natural gas discoveries in the Deepwater Trend of the Gulf of Mexico. We are expanding our platform business with new platforms to serve the Falcon and Marco Polo developments. Our natural gas gathering business will see growth in the future with the addition of the Falcon, Phoenix, Marco Polo, and Medusa natural gas gathering pipelines. Finally, we are significantly expanding our oil pipeline presence with our new Cameron Highway Oil Pipeline and Marco Polo oil gathering systems.







Viosca Knoll 817 Platform

This full-service platform located in the eastern Gulf of Mexico provides processing and compression for our Viosca Knoll Pipeline producers from flextrend and deepwater fields and serves as a key compressor station.

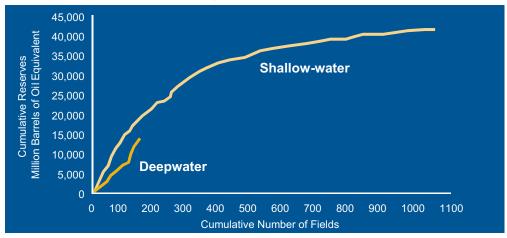
Since 1994, GulfTerra Energy Partners has developed and participated in almost \$2 billion of projects in the Gulf of Mexico. As can be seen from the adjacent map, we are well positioned for future deepwater activity with gas and oil pipelines and platforms from the western to eastern Gulf. By 2005, we will have direct connects or access to approximately 50 percent of the deepwater platforms in the Gulf of Mexico.

The Minerals Management Service estimates potential reserves of up to 40 billion barrels of oil and 139 Tcf of gas to be recovered from the deepwater. The graph below shows the development of the Gulf of Mexico shelf in relation to how the deepwater has developed to date. We are in the early stages of development of the deepwater and should see continued growth for many years to come.

We are extremely proud of our accomplishments to date but remain very focused on the future. With our asset position and commercial and technical expertise, we believe we will continue to benefit from growth opportunities in the deepwater Gulf of Mexico.

Deepwater Reserve Potential

Includes Reserves, Resources, and Industry-announced Discoveries



Source: MMS 2002-021 publication "Deepwater Gulf of Mexico 2002: America's Expanding Frontier."



Falcon Nest This 400 MMcf/d platform processes production from the Falcon field located 32 miles south of the platform.

2003



and Falcon Gas Pipeline placed into service

> 05/2003 Name changed to GulfTerra





3rd quarter/2003 Medusa Natural Gas Pipeline extension of Viosca Knoll to be in service



4th quarter/2003 Marco Polo Platform to be installed Marco Polo

2004

1st quarter/2004 Marco Polo Platform and nil and natural gas pipelines to begin service

2nd quarter/2004 Phoenix gathering system to be in service



3rd quarter/2004 Cameron Highway Oil Pipeline to be in service





Directors and Officers

Directors of GulfTerra Energy Company, L.L.C.



Left to right: James H. Lytal, Michael B. Bracy, Kenneth L. Smalley, H. Douglas Church, and Robert G. Phillips.

Michael B. Bracy 1,2

Former Director, Executive Vice President, and Chief Financial Officer of NorAm Energy Corp.

H. Douglas Church 1,2

Former Senior Vice President, Transmission, Engineering, and Environmental for Texas Eastern Transmission Company

James H. Lytal

President of GulfTerra Energy Partners

Robert G. Phillips

Chairman of the Board and Chief Executive Officer of GulfTerra Energy Partners, President of El Paso Field Services

Kenneth L. Smalley 1,2

Former Senior Vice President of Phillips Petroleum Company, President of Phillips 66 Natural Gas Company

Principal Officers

Robert G. Phillips

Chairman of the Board and Chief Executive Officer

James H. Lytal

President

D. Mark Leland

Senior Vice President and Chief Operating Officer

Keith B. Forman

Vice President and Chief Financial Officer

Joe N. Averett, Jr.

Vice President, Storage Services

David H. Eargle

Vice President, Commercial West

Jerry J. Langdon

Vice President, Texas Pipelines

David L. Siddall

Corporate Secretary

Kathy A. Welch

Vice President, Controller

E. Randall West

Vice President, Operations and Engineering

¹ Audit and Conflicts Committee

² Governance and Compensation Committee

Financial Statements

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Report of Independent Accountants

To the Unitholders of El Paso Energy Partners, L.P. and the Board of Directors and Stockholder of El Paso Energy Partners Company, as General Partner:

Pricewaterhouse Copus us

In our opinion, the consolidated balance sheets and the related consolidated statements of income, of cash flows, of partners' capital and of comprehensive income and changes in accumulated other comprehensive income present fairly, in all material respects, the financial position of El Paso Energy Partners, L.P. and its subsidiaries (the "Partnership") at December 31, 2002 and 2001, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2002 in conformity with accounting principles generally accepted in the United States of America. 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 of these statements in accordance with auditing standards generally accepted in the United States of America, which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, 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.

As discussed in Note 1 to the consolidated financial statements, the Partnership changed its method of accounting for the impairment and disposal of long-lived assets effective January 1, 2002.

Houston, Texas March 24, 2003

Consolidated Financial Statements

Consolidated Statements of Income

(In thousands, except per unit amounts)

	Year Ended December 31,					
	2002	2001	2000			
Operating revenues						
Natural gas pipelines and plants						
Natural gas sales	\$ 85,001	\$ 59,701	\$ 34,531			
NGL sales	32,978	_	_			
Gathering and transportation	194,336	33,849	28,968			
Processing	45,266	7,133	_			
	357,581	100,683	63,499			
Oil and NGL logistics						
Oil sales	10,636	_	_			
Oil transportation	8,364	7,082	8,307			
Fractionation	26,356	25,245	_			
NGL storage	2,817	_	_			
	48,173	32,327	8,307			
Platform services	16,672	15,385	13,875			
Natural gas storage	28,602	19,373	6,182			
Other — oil and natural gas production	16,890	25,638	20,552			
	467,918	193,406	112,415			
Operating expenses						
Cost of natural gas, oil and other products	119,347	51,542	28,160			
Operation and maintenance	115,162	33,279	14,461			
Depreciation, depletion and amortization	72,126	34,778	27,743			
Asset impairment charge		3,921				
	306,635	123,520	70,364			
Operating income	161,283	69,886	42,051			
Other income (loss)						
Earnings from unconsolidated affiliates	13,639	8,449	22,931			
Net loss on sale of assets	(473)	(11,367)	_			
Minority interest in consolidated subsidiaries	60	(100)	(95)			
Other income	1,537	28,726	2,377			
Interest and debt expense	83,494	41,542	46,820			
Income tax benefit			(305)			
Income from continuing operations	92,552	54,052	20,749			
Income (loss) from discontinued operations	5,136	1,097	(252)			
Net income	\$ 97,688	\$ 55,149	\$ 20,497			

Consolidated Statements of Income — (continued)

(In thousands, except per unit amounts)

Year Ended December 31,	
-------------------------	--

						,
		2002		2001		2000
Income (loss) allocation						
General partner						
Continuing operations	\$	42,082	\$	24,650	\$	15,581
Discontinued operations		51		11		(3)
	\$	42,133	\$	24,661	\$	15,578
Series B unitholders	\$	14,688	\$	17,228	\$	5,668
Series C unitholders	\$	1,507	\$		\$	_
Common unitholders			_		_	
Continuing operations	\$	34,275	\$	12,174	\$	(500)
Discontinued operations		5,085		1,086		(249)
	\$	39,360	\$	13,260	\$	(749)
Basic and diluted earnings per common unit	=		=		=	
Continuing operations	\$	0.80	\$	0.35	\$	(0.02)
Discontinued operations		0.12		0.03		(0.01)
Net income (loss)	\$	0.92	\$	0.38	\$	(0.03)
Weighted average number of common units outstanding	=	42,814		34,376	_	29,077
	=		=		=	

Consolidated Balance Sheets

(In thousands)

	Dece	mber 31,
	2002	2001
ASSETS		
Current assets		
Cash and cash equivalents	\$ 36,099	\$ 13,084
Accounts receivable, net	.00 = .0	00.400
Trade	139,519	33,162
Affiliates	83,826	23,013
Affiliated note receivable	17,100	_
Other current assets	3,451	557
Total current assets	279,995	69,816
Property, plant and equipment, net	2,724,938	917,867
Intangible assets	3,970	_
Assets held for sale, net	_	185,560
Investment in processing agreement	_	119,981
Investments in unconsolidated affiliates	78,851	34,442
Other noncurrent assets	43,142	29,754
Total assets	\$ 3,130,896	\$ 1,357,420
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities		
Accounts payable		
Trade	\$ 126,724	\$ 14,987
Affiliates	86,144	10,068
Accrued interest	15,028	6,401
Current maturities of senior secured term loan	5,000	_
Current maturities of limited recourse term loan	_	19,000
Other current liabilities	21,195	4,159
Total current liabilities	254,091	54,615
Revolving credit facility	491,000	300,000
Senior secured term loans, less current maturities	552,500	_
Limited recourse term loan, less current maturities	_	76,000
Long-term debt	857,786	425,000
Other noncurrent liabilities	23,725	1,079
Total liabilities	2,179,102	856,694
Commitments and contingencies		
Minority interest	1,942	_
Partners' capital	.,0 .2	
Limited partners		
Series B preference units; 125,392 units in 2002 and 2001 issued and outstanding	157,584	142,896
Series C units; 10,937,500 units in 2002 issued and outstanding	351,507	-
Accumulated other comprehensive loss allocated to Series C units' interest	(942)	_
Common units; 44,030,314 units in 2002 and 39,738,974 units in 2001	(0 1/2)	
issued and outstanding	437,773	354,019
Accumulated other comprehensive loss allocated to common units' interest	(4,623)	(1,259)
General partner	8,610	5,083
Accumulated other comprehensive loss allocated to general partner's interests	(57)	(13)
Total partners' capital	949,852	500,726
Total liabilities and partners' capital	\$ 3,130,896	\$ 1,357,420
rotal habilition and partition outside		1,001,420

See accompanying notes.

Consolidated Statements of Cash Flows

(In thousands)

(In thousands)			
		r Ended Decembe	
	2002	2001	2000
Cash flows from operating activities			
Net income		\$ 55,149	\$ 20,497
Less income (loss) from discontinued operations	5,136	1,097	(252)
Income from continuing operations	92,552	54,052	20,749
Adjustments to reconcile net income to net cash provided			
by operating activities			
Depreciation, depletion and amortization	72,126	34,778	27,743
Asset impairment charge	_	3,921	_
Distributed earnings of unconsolidated affiliates			
Earnings from unconsolidated affiliates	(13,639)	(8,449)	(22,931)
Distributions from unconsolidated affiliates	17,804	35,062	33,960
Net loss on sale of assets	473	11,367	_
Other noncash items	4,256	4,308	(13)
Working capital changes, net of effects of acquisitions			
and noncash transactions			
Accounts receivable	(169,106)	(41,954)	(17,351)
Other current assets	(3,144)	125	1,295
Accounts payable, accrued interest and other current	(0,111)	120	1,200
liabilities	162,872	(259)	5,210
Noncurrent receivable from El Paso Corporation	8,437	(10,362)	5,210
,		. , ,	_
Other	(1,875)	(173)	40,000
Net cash provided by continuing operations	170,756	82,416	48,662
Net cash provided by (used in) discontinued operations	5,244	4,968	(252)
Net cash provided by operating activities	176,000	87,384	48,410
Cash flows from investing activities			
Development expenditures for oil and natural gas			
properties	(1,682)	(2,018)	(172)
Additions to property, plant and equipment	(202,541)	(508,347)	(1,849)
Proceeds from sale of assets	5,460	109,126	_
Additions to investments in unconsolidated affiliates	(38,275)	(1,487)	(8,979)
Cash paid for acquisitions, net of cash acquired	(1,164,856)	(28,414)	(26,476)
Other	_	_	(381)
Net cash used in investing activities of continuing			-
operations	(1,401,894)	(431,140)	(37,857)
Net cash provided by (used in) investing activities of			
discontinued operations	186,477	(68,560)	(88,356)
Net cash used in investing activities	(1,215,417)	(499,700)	(126,213)
Cash flows from financing activities			
Net proceeds from revolving credit facility	366,219	559,994	152,043
Repayments of revolving credit facility	(177,000)	(581,000)	(125,000)
Net proceeds from EPN Holding term credit facility	530,136	_	_
EPN Holding term credit facility repayments	(375,000)	_	_
Net proceeds from senior secured acquisition term loan	233,236	_	_
Net proceeds from senior secured term loan	156,530	_	_
Net proceeds from issuance of long-term debt	423,528	243,032	
		240,002	
Argo term loan repayment	(95,000)	206 600	100,634
Net proceeds from issuance of common units	150,159	286,699	100,034
Redemption of Series B preference units	_	(50,000)	(004)
Redemption of publicly held preference units	4.005	- 0.040	(804)
Contributions from general partner	4,095	2,843	2,785
Distributions to partners	(154,468)	(106,409)	(79,330)
Net cash provided by financing activities of continuing			
operations	1,062,435	355,159	50,328
Net cash provided by (used in) financing activities of			
discontinued operations	(3)	49,960	43,554
Net cash provided by financing activities	1,062,432	405,119	93,882
Net increase (decrease) in cash and cash equivalents	23,015	(7,197)	16,079
Cash and cash equivalents at beginning of year	13,084	20,281	4,202
Cash and cash equivalents at end of year	\$ 36,099	\$ 13,084	\$ 20,281

Consolidated Statements of Partners' Capital

(In thousands)

	Series B	Series B								
	Preference	Preference	Series C	Series C I	Preference	Preference	Common	Common	General	
	Units	Unitholders	Units (1)	Unit holders	Units	Unitholders	Units	Unitholders	Partner ⁽²⁾	Total
Partners' capital at										
January 1, 2000	_	\$ -	_	\$ -	290	\$ 2,969	26,739	\$93,277	\$ 243	\$ 96,489
Net income (loss)(3)	_	5,668	_	_	_	241	_	(990)	15,578	20,497
Conversion of preference										
units into common units	_	_	_	_	(211)	(2,165)	211	2,165	_	_
Redemption of remaining										
preference units	_	_	_	_	(79)	(804)	_	_	_	(804)
Issuance of common units	_	_	_	_	_	_	4,600	100,634	_	100,634
General partner										
contribution related to										
the issuance of common										
units	_	_	_	_	_	_	_	_	2,785	2,785
Issuance of Series B									,	,
preference units	170	170,000	_	_	_	_	_	_	_	170,000
Cash distributions	_		_	_	_	(241)	_	(62,284)	(16,005)	(78,530)
Partners' capital at								(02,204)	(10,000)	(70,000)
December 31, 2000	170	175,668	_	_	_	_	31,550	132,802	2,601	311,071
Net income ⁽³⁾		17,228					01,000	13,260	24,661	55,149
	_	17,220	_	_	_	_	_			
Other comprehensive loss	_	_	_	_	_	_	_	(1,259)	(13)	(1,272)
Issuance of common							0.400	000.000		000 000
units	_	_	_	_	_	_	8,189	286,699	_	286,699
Unamortized unit option								0.404		0.101
compensation	_	_	_	_	_	_	_	2,161	_	2,161
Redemption of Series B										
preference units	(45)	(50,000)	_	_	_	_	_	_	_	(50,000)
General partner										
contribution related to										
the issuance of common										
units	_	_	_	_	_	_	_	_	2,843	2,843
Cash distributions								(80,903)	(25,022)	(105,925)
Partners' capital at										
December 31, 2001	125	142,896	_	_	_	_	39,739	352,760	5,070	500,726
Net income ⁽³⁾	_	14,688	_	1,507	_	_	_	39,360	42,133	97,688
Issuance of Series C										
units	_	_	10,938	350,000	_	_	_	_	_	350,000
Other comprehensive loss	_	_	_	(942)	_	_	_	(3,364)	(44)	(4,350)
Issuance of common units	_	_	_	_	_	_	4,291	156,072	_	156,072
Unamortized unit option										
compensation	_	_	_	_	_	_	_	89	_	89
General partner										
contribution related to										
the issuance of Series C										
units and common units		_		_				_	4,095	4,095
Cash distributions	_	_	_	_	_	_	_	(111,767)	(42,701)	(154,468)
Partners' capital at								(111,707)	(42,701)	(104,400)
December 31, 2002	125	¢157504	10,938	\$350,565		Ċ	44,030	\$433,150	\$ 8,553	\$949,852
December 31, 2002	====	\$157,584 ======	=====	=====		\$ <u> </u>	=====	=====	\$ 8,553	=======================================

⁽⁹⁾ We issued 10,937,500 of our Series C units to El Paso Corporation for a value of \$350 million in connection with our acquisition of the San Juan assets. A discussion of this new class of units is included in Note 8.

⁽²⁾ El Paso Energy Partners Company, a wholly owned subsidiary of El Paso Corporation, owns a one percent general partner interest in us.

⁽³⁾ Income allocation to our general partner includes both its incentive distributions and its one percent ownership interest.

Consolidated Statements of Comprehensive Income and Changes in Accumulated Other Comprehensive Income

(In thousands)

Comprehensive Income

	Year	Ende	ed Decem	ber	31,
	2002		2001 2000		
Net income	\$ 97,688	\$	55,149	\$	20,497
Other comprehensive income (loss)	(4,350)		(1,272)		_
Total comprehensive income	\$ 93,338	\$	53,877	\$	20,497

Accumulated Other Comprehensive Income

	Year Ended December 31,					
	2002 2001			2001	2000	
Beginning balance	\$	(1,272)	\$	S –	\$	_
Unrealized mark-to-market losses on cash flow hedges						
arising during period		(6,428)		(1,682)		_
Reclassification adjustments for changes in initial						
value of derivative instruments to settlement						
date		1,579		410		_
Accumulated other comprehensive income from investment						
in unconsolidated affiliate		499		_		_
Ending balance	\$	(5,622)	\$	5 (1,272)	\$	_

See accompanying notes. 27

Notes to Consolidated Financial Statements

1. Summary of Significant Accounting Policies

Organization

We are a publicly held Delaware master limited partnership established in 1993 for the purpose of providing midstream energy services, including gathering, transportation, fractionation, storage and other related activities for producers of natural gas and oil, onshore and offshore in the Gulf of Mexico. As of December 31, 2002, we had 44,030,314 common units outstanding representing limited partner interests, 125,392 Series B preference units outstanding representing preference interests and 10,937,500 Series C units outstanding representing non-voting limited partner interests. On that date, the public owned 32,356,069 common units, or 73.5 percent of our outstanding common units, and El Paso Corporation, through its subsidiaries, owned 11,674,245 common units, or 26.5 percent of our outstanding common units, all of our Series B preference units, all of our Series C units and our one percent general partner interest.

Basis of Presentation and Principles of Consolidation

Our consolidated financial statements include the accounts of all majority-owned, controlled subsidiaries after the elimination of all significant intercompany accounts and transactions. We account for investments in companies where we have the ability to exert significant influence over, but not control over operating and financial policies, using the equity method of accounting. Prior to May 2001, our general partner's approximate one percent non-managing interest in twelve of our subsidiaries represented the minority interest in our consolidated financial statements. In May 2001, we purchased our general partner's one percent non-managing ownership interests. During 2002, third parties have minority ownership interests in Matagorda Island Area Gathering System and Arizona Gas, L.L.C. The assets, liabilities and operations of these entities are included in our financial statements and we account for the third party ownership interest as minority interest in our balance sheet and as minority interest in consolidated subsidiaries in our statement of income. Our consolidated financial statements for prior periods include reclassifications that were made to conform to the current year presentation. Those reclassifications have no impact on reported net income or partners' capital. We have reflected the results of operations from our Prince assets disposition as discontinued operations for all periods presented. See Note 2 for a further discussion of our Prince assets disposition.

Use of Estimates

The preparation of our financial statements in conformity with accounting principles generally accepted in the United States requires us to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and disclosure of contingent assets and liabilities that exist at the date of our financial statements. While we believe our estimates are appropriate, actual results can, and often do, differ from those estimates.

Accounting for Regulated Operations

Our HIOS interstate natural gas system and our Petal storage facility are subject to the jurisdiction of FERC in accordance with the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978. Each system operates under separate FERC approved tariffs that establish rates, terms and conditions under which each system provides services to its customers. Our businesses that are subject to the regulations and accounting requirements of FERC have followed the accounting requirements of Statement of Financial Accounting Standards (SFAS) No. 71, Accounting for the Effects of Certain Types of Regulation, which may differ from the accounting requirements of our non-regulated entities. Transactions that have been recorded differently as a result of regulatory accounting requirements include the capitalization of an equity return component on regulated capital projects, and other costs and taxes included in, or expected to be included in, future rates.

When the accounting method followed is required by or allowed by the regulatory authority for rate-making purposes, the method conforms to the generally accepted accounting principle (GAAP) of matching costs with the revenues to which they apply.

Cash and Cash Equivalents

We consider short-term investments with little risk of change in value because of changes in interest rates and purchased with an original maturity of less than three months to be cash equivalents.

Allowance for Doubtful Accounts

We have established an allowance for losses on accounts which may become uncollectible. Collectibility is reviewed regularly and the allowance is adjusted as necessary, primarily under the specific identification method. At December 31, 2002 and 2001, the allowance was \$2.5 million and \$1.8 million.

Natural Gas Imbalances

Natural gas imbalances result from differences in gas volumes received from and delivered to our customers and arise when a customer delivers more or less gas into our pipelines than they take out. These imbalances are settled in kind through a tracking mechanism, negotiated cash-outs between parties, or are subject to a cash-out procedure and are valued at prices representing the estimated value of these imbalances upon settlement. Changes in natural gas prices may impact our valuation. We do not value our imbalances based on current month prices because it is not likely that we would purchase or receive natural gas at that point in time to settle the imbalance. Natural gas imbalances are reflected in accounts receivable or accounts payable, as appropriate, in our accompanying consolidated balance sheets. Our imbalances at December 31, 2002, arose as a result of our acquisitions during 2002. We did not have significant imbalances at December 31, 2001. Our imbalance receivables and imbalance payables were as follows at December 31, 2002 (in thousands):

	1	ml	bal	ar	ice	Re	ec	eiv	′ab	ıles
--	---	----	-----	----	-----	----	----	-----	-----	------

Trade	\$ 88,929
Affiliates	\$ 15,460
Imbalance Payables	
Trade	\$ 104,035
Affiliates	\$ 22,316

Property, Plant and Equipment

We record our property, plant and equipment at its original cost of construction or, upon acquisition, the fair value of the asset acquired. Additionally, we capitalize direct costs, such as labor and materials, and indirect costs, such as overhead, interest and in our regulated businesses that apply the provisions of SFAS No. 71, an equity return component. We also capitalize the major units of property replacements or improvements and expense minor items including repair and maintenance costs.

For our regulated interstate system and storage facility we use the composite (group) method to depreciate regulated property, plant and equipment. Under this method, assets with similar lives and other characteristics are grouped and depreciated as one asset. We apply the depreciation rate approved in our tariff, to the total cost of the group, until its net book value equals its estimated salvage value.

Our non-regulated gathering pipelines, platforms and related facilities, processing facilities and equipment, and storage facilities and equipment are depreciated on a straight-line basis over the estimated useful lives which are as follows:

Gathering pipelines	. 5-40 years
Platforms and facilities	. 18-30 years
Processing facilities	. 25-30 years
Storage facilities	. 25-30 years

We account for our oil and natural gas exploration and production activities using the successful efforts method of accounting. Under this method, costs of successful exploratory wells, developmental wells and acquisitions of mineral leasehold interests are capitalized. Production, exploratory dry hole and other exploration costs, including geological and geophysical costs and delay rentals, are expensed as incurred. Unproved properties are assessed periodically and any impairment in value is recognized currently as depreciation, depletion and amortization expense.

Depreciation, depletion and amortization of the capitalized costs of producing oil and natural gas properties, consisting principally of tangible and intangible costs incurred in developing a property and costs of productive leasehold interests, are computed on the unit-of-production method. Unit-of-production rates are based on annual estimates of remaining proved developed reserves or proved reserves, as appropriate, for each property.

Estimated dismantlement, restoration and abandonment costs and estimated residual salvage values are taken into account in determining depreciation provisions for gathering pipelines, platforms, related facilities and oil and natural gas properties. At December 31, 2002 and 2001, accrued abandonment costs were \$24.6 million and \$23.5 million. As discussed below, upon our adoption of SFAS No. 143 *Accounting for Asset Retirement Obligations* the amounts accrued and capitalized will be adjusted to conform to the provisions of that statement.

Retirements, sales and disposals of assets are recorded by eliminating the related costs and accumulated depreciation, depletion and amortization of the disposed assets with any resulting gain or loss reflected in income.

Goodwill and Other Intangible Assets

We adopted the provisions of SFAS No. 142 *Goodwill and Other Intangible Assets* on January 1, 2002, except for goodwill and intangible assets we acquired after June 30, 2001 for which we adopted the provisions immediately. Accordingly, we record identifiable intangible assets we acquire individually or with a group of other assets at fair value upon acquisition. Identifiable intangible assets with finite useful lives are amortized to expense over the estimated useful life of the asset. Identifiable intangible assets with indefinite useful lives and goodwill are evaluated annually for impairment by comparison of their carrying amounts with the fair value of the individual assets. We recognize an impairment loss in income for the amount by which the carrying value of any identifiable intangible asset or goodwill exceeds the fair value of the specific assets. As of December 31, 2002 and 2001, we had no goodwill, other than described below.

As of December 31, 2002 and 2001, the carrying amount of our equity investment in Poseidon exceeded the underlying equity in net assets by approximately \$3.0 million. With our adoption of SFAS No. 142 on January 1, 2002, we no longer amortize this excess amount and will test for impairment if an event occurs that indicates there may be a loss in value. Prior to January 1, 2002, we amortized this excess amount using the straight line method over approximately 30 years. This excess amount is reflected on our accompanying consolidated balance sheets in investments in unconsolidated affiliates. Our adoption of this statement did not have a material impact on our financial position or results of operations.

As part of our acquisition of the EPN Holding assets and the San Juan assets, we obtained intangible assets representing contractual rights under dedication and transportation agreements with producers. As of December 31, 2002, the value of these intangible assets was approximately \$4.0 million and is reflected on our accompanying consolidated balance sheet as intangible assets. We amortize these intangible assets to expense using the units-of-production method over the expected lives of the reserves ranging from 20 to 45 years.

Impairment and Disposal of Long-Lived Assets

We adopted the provisions of SFAS No. 144 *Accounting for the Impairment or Disposal of Long-Lived Assets* on January 1, 2002. Accordingly, we evaluate the recoverability of selected long-lived assets when adverse events or changes in circumstances indicate that the carrying value of an asset or group of assets may not be recoverable.

We determine the recoverability of an asset or group of assets by estimating the undiscounted cash flows expected to result from the use and eventual disposition of the asset or group of assets at the lowest level for which separate cash flows can be measured. If the total of the undiscounted cash flows is less that the carrying amount for the assets, we estimate the fair value of the asset or group of assets and recognize the amount by which the carrying value exceeds the fair value as an impairment loss in income from operations in the period the impairment is determined.

Additionally, as required by SFAS No. 144, we classify long-lived assets to be disposed of other than by sale (e.g., abandonment, exchange or distribution) as held and used until the item is abandoned, exchanged or distributed. We evaluate assets to be disposed of other than by sale for impairment and recognize a loss for the excess of the carrying value over the fair value. Long-lived assets to be disposed of through sale recognition meeting specific criteria are classified as "Held for Sale" and measured at the lower of their cost or fair value less cost to sell. We report the results of operations of a component classified as held for sale, including any gain or loss recognized in discontinued operations in the period(s) in which they occur and all prior periods presented.

Capitalization of Interest

Interest and other financing costs are capitalized in connection with construction and drilling activities as part of the cost of the asset and amortized over the related asset's estimated useful life.

Debt Issue Costs

Debt issue costs are capitalized and amortized over the life of the related indebtedness using the effective interest method. Any unamortized debt issue costs are expensed at the time the related indebtedness is repaid or terminated. At December 31, 2002 and 2001, the unamortized amount of our debt issue costs included in other noncurrent assets was \$32.6 million and \$17.0 million.

Revenue Recognition and Cost of Natural Gas, Oil and Other Products

Revenue from gathering and transportation of hydrocarbons is recognized upon receipt of the hydrocarbons into the pipeline systems. Revenue from commodity sales is recognized upon delivery. Commodity storage revenues and platform access revenues consist primarily of fixed fees for capacity reservation and some of the transportation contracts on our Viosca Knoll system and our Indian Basin lateral also contain a fixed fee to reserve transportation capacity. These fixed fees are recognized during the month in which the capacity is reserved by the customer, regardless of how much capacity is actually used. Revenue from processing services, treating services and fractionation services is recognized in the period the services are provided. Interruptible revenues from natural gas storage, which are generated by providing excess storage capacity, are variable in nature and are recognized when the service is provided. Other revenues generally are recorded when services have been provided or products have been delivered.

Prior to 2002, our cost of natural gas consisted primarily of natural gas purchased at EPIA for resale. As a result of our acquisition of the EPN Holding assets and the San Juan assets, we are now incurring additional costs related to system imbalances and for the purchase of natural gas as part of our producer services activities. As a convenience for our producers, we may purchase natural gas from them at the wellhead at an index price less an amount that compensates us for our gathering services. We then sell this gas into the open market at points on our system at the same index price. We reflect these sales in our revenues and the related purchases as cost of natural gas on the accompanying consolidated statements of income.

Typhoon Oil Pipeline's transportation agreement with BHP and Chevron Texaco provides that Typhoon Oil purchase the oil produced at the inlet of its pipeline for an index price less an amount that compensates Typhoon Oil for transportation services. At the outlet of its pipeline, Typhoon Oil resells this oil back to these producers at the same index price. We reflect these sales in our revenues and the related purchases as cost of oil.

Environmental Costs

We expense or capitalize expenditures for ongoing compliance with environmental regulations that relate to past or current operations as appropriate. We expense amounts for clean up of existing environmental contamination caused by past operations which do not benefit future periods. We record liabilities when our environmental assessments indicate that remediation efforts are probable, and the costs can be reasonably estimated. Estimates of our liabilities are based on currently available facts, existing technology and presently enacted laws and regulations taking into consideration the likely effects of inflation and other societal and economic factors, and include estimates of associated legal costs. These amounts also consider prior experience in remediating contaminated sites, other companies' clean-up experience and data released by the Environmental Protection Agency (EPA) or other organizations. These estimates are subject to revision in future periods based on actual costs or new circumstances and are included in our balance sheet in other noncurrent liabilities at their undiscounted amounts.

Accounting for Price Risk Management Activities

Our business activities expose us to a variety of risks, including commodity price risk and interest rate risk. From time to time we engage in price risk management activities for non-trading purposes to manage market risks associated with commodities we purchase and sell and interest rates on variable rate debt. Our price risk management activities involve the use of a variety of derivative financial instruments, including:

- · exchange-traded future contracts that involve cash settlement;
- · forward contracts that involve cash settlements or physical delivery of a commodity; and
- swap contracts that require payments to (or receipts from) counterparties based on the difference between a fixed and a variable price, or two variable prices, for a commodity or variable rate debt instrument.

Beginning in 2001, we account for all our derivative instruments in our financial statements under SFAS No. 133, *Accounting for Derivatives and Hedging Activities.* We record all derivatives in our balance sheet at their fair value as other assets or other liabilities and classify them as current or noncurrent based upon their anticipated settlement date.

For those instruments entered into to hedge risk and which qualify as hedges, we apply the provisions of SFAS No. 133, and the accounting treatment depends on each instrument's intended use and how it is designated. In addition to its designation, a hedge must be effective. To be effective, changes in the value of the derivative or its resulting cash flows must substantially offset changes in the value or cash flows of the item being hedged.

During 2000, prior to our adoption of SFAS No. 133, we entered into commodity price swap instruments for non-trading purposes to manage our exposure to price fluctuations on anticipated natural gas and crude oil sales transactions.

We formally document all relationships between hedging instruments and hedged items, as well as our risk management objectives and strategies for undertaking various hedge transactions. All hedging instruments are linked to the hedged asset, liability, firm commitment or forecasted transaction. We also assess, both at the inception of the hedge and on an on-going basis, whether the derivatives that are used in our hedging transactions are highly effective in offsetting changes in cash flows or fair values of the hedged items. We discontinue hedge accounting prospectively if we determine that a derivative is not highly effective as a hedge or if we decide to discontinue the hedging relationship.

During 2002 and 2001, we entered into cash flow hedges that qualify for SFAS No. 133 treatment. Changes in the fair value of a derivative designated as a cash flow hedge are recorded in accumulated other comprehensive income for the portion of the change in value of the derivative that is effective. The ineffective portion of the derivative is recorded in earnings in the current period. Classification in the income statement of the ineffective portion is based on the income classification of the item being hedged. We reclassify the gains or losses resulting from the sale, maturity, extinguishment or termination of derivative instruments designated as hedges from accumulated other comprehensive income to operating income in our consolidated statements of income. We classify cash inflows and outflows

associated with the settlement of our derivative transactions as cash flows from operating activities in our consolidated statements of cash flows.

We also record our ownership percentage of the changes in the fair value of derivatives of our investments in unconsolidated affiliates in accumulated other comprehensive income.

We may also purchase and sell instruments to economically hedge price fluctuations in the commodity markets. These instruments are not documented as hedges due to their short-term nature, or do not qualify under the provisions of SFAS No. 133 for hedge accounting due to the terms in the instruments. Where such derivatives do not qualify, changes in their fair value are recorded in earnings in the current period.

In August 2002, we entered into a derivative financial instrument to hedge our exposure during 2003 to changes in natural gas prices in the San Juan Basin in anticipation of our acquisition of the San Juan assets. From August 2002 through our acquisition date, November 27, 2002, we accounted for this derivative under mark-to-market accounting since it did not qualify for hedge accounting under SFAS No. 133. Beginning with the acquisition date in November 2002, we have designated this derivative as a cash flow hedge and are accounting for it as such under SFAS No. 133.

To qualify for hedge accounting, prior to our adoption of SFAS No. 133, the transactions must have reduced the price risk of the underlying hedged items, be designated as hedges at inception, and resulted in cash flows and financial impacts which were inversely correlated to the position being hedged. If correlation ceased to exist, hedge accounting was terminated and mark-to-market accounting was applied. Gains and losses resulting from hedging activities and the termination of any hedging instruments were initially deferred and included as an increase or decrease to oil and natural gas sales in the period in which the hedged production was sold.

During the normal course of our business, we may enter into contracts that qualify as derivatives under the provisions of SFAS No. 133. As a result, we evaluate our contracts to determine whether derivative accounting is appropriate. Contracts that meet the criteria of a derivative and qualify as "normal purchases" and "normal sales", as those terms are defined in SFAS No. 133, may be excluded from SFAS No. 133 treatment.

Income Taxes

As of December 31, 2002, neither we nor any of our subsidiaries are taxable entities. Tarpon Transmission Company, our only taxable entity in 2000, was sold in January 2001, and as a result, we incurred no income tax liability in 2001 and 2002. However, the taxable income or loss resulting from our operations will ultimately be included in the federal and state income tax returns of the general and limited partners. Individual partners will have different investment bases depending upon the timing and price of their acquisition of partnership units. Further, each partner's tax accounting, which is partially dependent upon his tax position, may differ from the accounting followed in the consolidated financial statements. Accordingly, there could be significant differences between each individual partner's tax basis and his share of the net assets reported in the consolidated financial statements. We do not have access to information about each individual partner's tax attributes and the aggregate tax bases cannot be readily determined.

We utilized SFAS No. 109, Accounting for Income Taxes, to account for Tarpon's income taxes subject to federal corporate income taxation. The income tax benefit reported in our consolidated statement of income for the year ended 2000 relates solely to Tarpon's book loss at the effective statutory income tax rate for the respective period since no material differences existed between book and taxable income. In January 2001, we sold our interest in Tarpon as a result of a FTC order. All of Tarpon's deferred tax liabilities were assumed by the buyer at the time of sale.

Income (Loss) per Common Unit

Basic income (loss) per common unit excludes dilution and is computed by dividing net income (loss) attributable to the common unitholders by the weighted average number of common units outstanding during the period. Diluted income (loss) per common unit reflects potential dilution and is computed by dividing net income (loss) attributable to the common unitholders by the weighted average number of common units outstanding during the period increased by the number of additional common units that would have been outstanding if the potentially dilutive units had been issued.

Basic income (loss) per common unit and diluted income (loss) per common unit are the same for the years ended December 31, 2002, 2001, and 2000, as the number of potentially dilutive units were so small as not to cause the diluted earnings per unit to be different from the basic earnings per unit. We include the outstanding publicly held preference units in 2000 in the basic and diluted net income (loss) per common unit calculation as if the publicly held preference units had been converted into common units. As of October 2000, all publicly held preference units have been converted into common units or redeemed.

Comprehensive Income

Our comprehensive income is determined based on net income (loss), adjusted for changes in accumulated other comprehensive income (loss) from our cash flow hedging activities associated with our EPIA operations, our Indian Basin processing plant, the San Juan assets and our unconsolidated affiliate, Poseidon Oil Pipeline Company, L.L.C.

Unit-Based Compensation

We apply the provisions of Accounting Principles Board Opinion (APB) No. 25 and related interpretations in accounting for unit options issued to former employees of our general partner and our board of directors. Accordingly, compensation expense is not recognized for these unit options unless the options were granted at an exercise price lower than the market price of common units on the grant date. We use fixed plan accounting for our restricted unit grants. We apply the provisions of SFAS No. 123, *Accounting for Stock-Based Compensation*, for unit options issued to employees of affiliates of our general partner. For these options, we amortize the fair value of these options as of the grant date over the vesting period of the grant.

In December 2002, the Financial Accounting Standards Board (FASB) issued SFAS No. 148, *Accounting for Stock-Based Compensation Transition and Disclosure*. This statement amends SFAS No. 123, to provide alternative methods of transition for a voluntary change to the fair value method of accounting for stock-based employee compensation. In addition, this statement amends the disclosure requirements of SFAS No. 123 to require prominent disclosures in both annual and interim financial statements about the methods of accounting for stock-based employee compensation and the effect of the method used on reported results. This statement is effective for the fiscal years ending after December 15, 2002. We have decided that we will continue to use APB No. 25 to value our stock-based compensation and will include data providing the pro forma income impacts of using the fair value method as required by SFAS No. 148.

The following discloses our stock-based compensation impact on net income as required by SFAS No. 148. If compensation expense for the stock-based compensation plans under our Omnibus Plan and Director Plan, as described in Note 8, accounted for under APB 25, had been determined applying the provisions of SFAS No. 123, and using the Black-Scholes weighted average fair value of options granted as described in Note 8, our net income (loss)

allocated to the common unitholders and net income (loss) per common unit for 2002, 2001, and 2000 would approximate the pro forma amounts below:

	Year Ended December 31,						
		2002	2001			2000	
		(In thousands,					
	except per unit amounts)						
Net income (loss) allocated to common unitholders, as							
reported	\$	39,360	\$	13,260	\$	(749)	
Less: Incremental stock-based employee compensation expense							
determined under fair value based method		(744)		(311)		(211)	
Pro forma net income (loss) allocated to common							
unitholders	\$	38,616	\$	12,949	\$	(960)	
Basic and diluted earnings per common unit, as reported	\$	0.92	\$	0.38	\$	(0.03)	
Basic and diluted earnings per common unit, pro forma	\$	0.90	\$	0.38	\$	(0.03)	

The effects of applying SFAS No. 123 in this pro forma disclosure are not indicative of future amounts.

Business Combinations

In July 2001, the FASB issued SFAS No. 141, *Business Combinations*. This statement requires that all transactions that fit the definition of a business combination be accounted for using the purchase method and prohibits the use of the pooling of interests method for all business combinations initiated after June 30, 2001. This statement also established specific criteria for the recognition of intangible assets separately from goodwill and requires unallocated negative goodwill to be written off immediately as an extraordinary item. The accounting for any business combination we undertake in the future will be impacted by this standard. We adopted the provisions of this standard and applied them to each of our acquisitions initiated after June 30, 2001. For transactions initiated prior to June 30, 2001, we applied the provisions of APB Opinion No. 16. Our adoption of SFAS No. 141 did not have a material effect on our financial position or results of operations.

New Accounting Pronouncements Issued But Not Yet Adopted

Accounting for Asset Retirement Obligations. In June 2001, the FASB issued SFAS No. 143, Accounting for Asset Retirement Obligations. This statement requires companies to record a liability for the estimated retirement and removal of assets used in their business. The liability is recorded at its fair value, with a corresponding asset which is depreciated over the remaining useful life of the long-lived asset to which the liability relates.

An ongoing expense will also be recognized for changes in the value of the liability as a result of the passage of time. The provisions of SFAS No. 143 are effective for fiscal years beginning after June 15, 2002 and relates primarily to our obligations to plug abandoned wells. We expect that we will record a cumulative effect of accounting change of approximately \$1.7 million, as an increase to income upon our adoption of SFAS No. 143 on January 1, 2003. We also expect to record non-current retirement assets of approximately \$7.0 million with useful lives ranging from 11 to 19 years and non-current retirement liabilities of approximately \$5.3 million on January 1, 2003.

Other than our obligations to plug and abandon wells, we expect we cannot estimate the costs to retire or remove assets used in our business because we believe the assets do not have definite lives or we do not have the legal obligation to abandon or dismantle the assets. Also, we believe that the life or underlying reserves cannot be estimated. Therefore, we will not record any liabilities relating to our assets, other than the liability associated with the plug and abandonment of wells.

Reporting Gains and Losses from the Early Extinguishment of Debt. In April 2002, the FASB issued SFAS No. 145, Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections. This statement addresses how to report gains or losses resulting from the early extinguishment of debt. Previously, any gains or losses were reported as an extraordinary item. Upon adoption of SFAS No. 145, an entity will be required to evaluate whether the debt extinguishment is extraordinary in nature, or whether they should be included in income from continuing operations. This statement is effective for our 2003 year-end reporting.

Accounting for Costs Associated with Exit or Disposal Activities. In July 2002, the FASB issued SFAS No. 146, Accounting for Costs Associated with Exit or Disposal Activities. This statement will require us to recognize costs associated with exit or disposal activities when they are incurred rather than when we commit to an exit or disposal plan. Examples of costs covered by this guidance include lease termination costs, employee severance costs, associated with a restructuring, discontinued operation, plant closing, or other exit or disposal activities. This statement is effective for fiscal years beginning after December 31, 2002 and will impact any exit or disposal activities that we initiate after January 1, 2003.

Accounting for Guarantees. In November 2002, the FASB issued FASB Interpretation (FIN) No. 45, Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others. This interpretation requires that companies record a liability for all guarantees issued after December 31, 2002, including financial, performance, and fair value guarantees. This liability is recorded at its fair value upon issuance, and does not affect any existing guarantees issued before January 31, 2003. This standard also requires expanded disclosures on all existing guarantees at December 31, 2002. We have included the required disclosures in Note 10.

Consolidation of Variable Interest Entities. In January 2003, the FASB issued FIN No. 46, Consolidation of Variable Interest Entities. This interpretation defines a variable interest entity as a legal entity whose equity owners do not have sufficient equity at risk and/or a controlling financial interest in the entity. This standard requires that companies consolidate a variable interest entity if it is allocated a majority of the entity's losses and/or returns, including fees paid by the entity. The provisions of FIN No. 46 are effective for all variable interest entities created after January 31, 2003, and are effective on July 1, 2003 for all variable interest entities created before January 31, 2003. We do not believe this statement will have any effect on us.

2. Acquisitions and Dispositions

San Juan Assets

In November 2002, we acquired from subsidiaries of El Paso Corporation, interests in assets we collectively refer to as the San Juan assets which consist of the following:

- 100 percent of El Paso Field Services' San Juan Gathering and Processing Businesses, which include a natural gas gathering system and related compression facilities, the Rattlesnake Treating Plant, a 50-percent equity interest in Coyote Gas Treating, L.L.C. which owns the Coyote natural gas treating facility and the remaining interests in the Chaco cryogenic natural gas processing plant we did not already own, all of which are located in the San Juan Basin of northwest New Mexico and southwestern Colorado;
- 100 percent of the Typhoon Oil Pipeline assets located in the Deepwater Trend area of the Gulf of Mexico.
 Typhoon Oil was placed in service in July 2001 and provides transportation of oil produced from the
 Typhoon field for delivery to a platform in Green Canyon Block 19 with onshore access through various oil pipelines;
- 100 percent of the Typhoon Gas Pipeline, which was placed in service in August 2001. Typhoon Gas is also located in the Deepwater Trend area of the Gulf of Mexico. The pipeline gathers natural gas from the Typhoon field for redelivery into El Paso Corporation's ANR Patterson System; and

 100 percent of the Coastal Liquids Partners' NGL Business, consisting of an integrated set of NGL assets that stretch from the Mexico border near McAllen, Texas, to Houston, Texas. This business includes a fractionation facility near Houston, Texas; a truck-loading terminal near McAllen, Texas, and leased underground NGL storage facilities.

We purchased the San Juan assets for \$782 million, \$766 million after adjustments for capital expenditures and actual working capital acquired. We financed the purchase of these assets with net proceeds from an offering of \$200 million of 10 5/8% Senior Subordinated Notes due 2012, borrowings of \$237.5 million under our senior secured acquisition term loan, our issuance, to El Paso Corporation, of \$350 million representing 10,937,500 of our Series C units valued at \$32 per unit and currently available funds. We acquired the San Juan assets because they are strategically located in active supply development areas and are supported by long-term contracts that provide us with growing and reliable cash flows consistent with our stated growth strategy.

In connection with this acquisition, El Paso Corporation is required, subject to specified conditions, to repurchase the Chaco plant from us for \$77 million in October 2021, and at that time we have the right to lease the plant from them for a period of 10 years with the option to renew the lease annually thereafter.

As a result of our acquisition of the San Juan assets, our financial results from the operation of the Chaco plant is significantly different from our results prior to the purchase as follows:

- We no longer receive fixed fee revenue of \$0.134/Dth for natural gas processed; rather, from a majority of our customers, we receive a processing fee of an in-kind portion of the NGL produced from the natural gas processed. We then sell these NGL and now our processing revenues are affected by changes in the price of NGL.
- · We no longer receive revenue for leasing the Chaco plant to El Paso Field Services.
- We no longer recognize amortization expense relating to our investment in processing agreement, which we terminated upon completing the acquisition. This decrease in amortization expense is offset by additional depreciation expense associated with the acquired assets.

In accordance with our procedures for evaluating and valuing material acquisitions with El Paso Corporation, our Audit and Conflicts Committee engaged independent financial advisors. Separate financial advisors delivered fairness opinions for the acquisition of the San Juan assets and the issuance of the Series C units. Based on these opinions, our Audit and Conflicts Committee and the full Board approved these transactions.

Notes to Consolidated Financial Statements, continued

The following table summarizes our allocation of the fair values of the assets acquired and liabilities assumed at November 27, 2002. Our allocation among the assets acquired is based on the results of an independent third-party appraisal. The purchase price allocation is subject to modification pending validation of working capital balances (in thousands):

	At
	November 27,
	2002
Note receivable	\$ 17,100
Property, plant and equipment	763,280
Intangible assets	470
Investment in unconsolidated affiliate	2,500
Total assets acquired	783,350
Imbalances payable	15,601
Other current liabilities	1,543
Total liabilities assumed	17,144
Net assets acquired	\$ 766,206

The acquired intangible assets represent contractual rights we obtained under dedication and transportation agreements with producers which we are amortizing to expense using the units-of-production method over the expected lives of the underlying reserves of approximately 20 years. We recorded adjustments to the purchase price of approximately \$16 million primarily for capital expenditures and actual working capital acquired. The purchase price allocation is subject to further adjustment as new information becomes available regarding the working capital accounts we acquired.

Our consolidated financial statements include the results of operations of the San Juan assets from the November 27, 2002 purchase date. We have included the assets and operating results of the El Paso Field Services' San Juan Gathering and Processing Businesses and the Typhoon Gas Pipeline in our natural gas pipelines and plants segment and the assets and operating results of the Typhoon Oil Pipeline and Coastal Liquids Partners' NGL Business in our oil and NGL logistics segment from the purchase date. The following selected unaudited pro forma financial information presents our consolidated operating results for the years ended December 31, 2002 and 2001 as if we acquired the San Juan assets on January 1, 2001:

	2002	2001	
	(In thousands,		
	except per	r unit amounts)	
Operating revenues	\$837,647	\$ 511,335	
Income from continuing operations	\$ 88,902	\$ 77,219	
Income allocated to common unitholders from continuing			
operations	\$ 25,738	\$ 16,687	
Basic and diluted net income per unit from continuing			
operations	\$ 0.60	\$ 0.43	

The unaudited pro forma financial information presented above is not necessarily indicative of the results of operations we might have realized had the transaction been completed at the beginning of the earliest period presented, nor do they necessarily indicate our consolidated operating results for any future period.

EPN Holding Assets

In April 2002, we acquired, through a series of related transactions, from subsidiaries of El Paso Corporation the following midstream assets located in Texas and New Mexico, which we collectively refer to as the EPN Holding assets:

- The Waha natural gas gathering and treating system and the Carlsbad natural gas gathering system which are generally located in the Permian Basin region of Texas and New Mexico.
- A 50 percent undivided interest in the Channel Pipeline System, an intrastate natural gas transmission system located along the Gulf Coast of Texas.
- The TPC Offshore pipeline system, a collection of natural gas gathering and transmission assets located offshore of Matagorda Bay, Texas, including the Oyster Lake and MILSP Condensate Separation and Stabilization facilities and other undivided interests in smaller pipelines.
- EPGT Texas Pipeline, L.P. which owns, among other assets, (i) the EPGT Texas intrastate pipeline system, (ii) the TGP natural gas lateral pipelines, (iii) the leased natural gas storage facilities located in Wharton County, Texas generally known as the Wilson Storage facility, (iv) an 80 percent undivided interest in the East Texas 36 inch pipeline, (v) a 50 percent undivided interest in the West Texas 30 inch pipeline, (vi) a 50 percent undivided interest in the North Texas 36 inch pipeline, (vii) the McMullen County natural gas gathering system, (viii) the Hidalgo County natural gas gathering system, (ix) a 22 percent undivided interest in the Bethel-Howard pipeline, and (x) a 75 percent undivided interest in the Longhorn pipeline.
- · El Paso Hub Services L.L.C. which owns certain contract rights and parcels of real property located in Texas.
- 100 percent of the outstanding joint venture interest in Warwink Gathering and Treating Company which
 owns among other assets, the Warwink natural gas gathering system located in the Permian Basin region of
 Texas and New Mexico.

In conjunction with the acquisition of the above assets, we obtained from another affiliate of El Paso Corporation, all of the equity interest in El Paso Indian Basin, L.P. which owns a 42.3 percent undivided, non-operating interest in the Indian Basin natural gas processing plant and treating facility located in southeastern New Mexico and the price risk management activities associated with the plant.

We acquired the EPN Holding assets to provide us with a significant new source of cash flow, greater diversification of our midstream asset base and to provide new long term internal growth opportunities in the Texas intrastate market. We purchased the EPN Holding assets for \$750 million, adjusted for the assumption of \$15 million of working capital related to natural gas imbalances resulting in net consideration of \$735 million comprised of the following:

- · \$420 million of cash;
- \$119 million of assumed short-term indebtedness payable to El Paso Corporation, which we subsequently repaid;
- · \$6 million in common units; and
- \$190 million in assets, comprised of our Prince TLP and our nine percent overriding royalty interest in the Prince field (see discussion below).

EPN Holding entered into a limited recourse credit agreement with a syndicate of commercial banks to finance substantially all of the cash consideration associated with this transaction. See Note 6 for additional discussion regarding the EPN Holding term credit facility.

The following table summarizes our allocation of the fair values of the assets acquired and liabilities assumed at April 8, 2002. Our allocation among the assets acquired is based on the results of an independent third-party appraisal. The purchase price allocation is subject to modification pending validation of working capital balances (in thousands):

	At April 8,
	2002
Current assets	\$ 2,217
Property, plant and equipment	775,997
Intangible assets	3,500
Total assets acquired	781,714
Current liabilities	25,578
Environmental liabilities	21,136
Total liabilities assumed	46,714
Net assets acquired	\$ 735,000

The acquired intangible assets represent contractual rights we obtained under dedication and transportation agreements with producers which we will amortize to expense using the units-of-production method over the expected lives of the underlying reserves ranging from 26 to 45 years. Additionally, we assumed environmental liabilities of \$21.1 million for estimated environmental remediation costs associated with the EPGT Texas intrastate pipeline assets as discussed in Note 10.

Our consolidated financial statements include the results of operations of the EPN Holding assets from the April 8, 2002 purchase date. We have included the assets and operating results of the Waha, Carlsbad and Warwink natural gas gathering systems; the Channel and TPC Offshore pipeline systems; and the EPGT Texas pipeline assets (excluding the Wilson Storage facility) in our natural gas pipelines and plants segment. Our 42.3 percent ownership interest in the assets and operating results of the Indian Basin plant are included in our oil and NGL logistics segment and the Wilson storage facility assets and operating results are included in our natural gas storage segment. The following selected unaudited pro forma information depicts our consolidated results of operations for the years ended December 31, 2002 and 2001 as if we acquired the EPN Holding assets on January 1, 2001:

	2002		2001
	(In thousands, except		
	per unit amounts)		
Operating revenues	\$ 540,154	\$	538,095
Income from continuing operations	\$ 114,517	\$	81,022
Income allocated to common unitholders from continuing			
operations	\$ 56,020	\$	38,874
Basic and diluted net income per unit from continuing			
operations	\$ 1.31	\$	1.13

2002

2001

The unaudited pro forma financial information presented above is not necessarily indicative of the results of operations we might have realized had the transaction been completed at the beginning of the earliest period presented, nor do they necessarily indicate our consolidated operating results for any future period.

Prince Assets

In connection with our April 2002 acquisition of the EPN Holding assets from El Paso Corporation, we sold our Prince tension leg platform (TLP), and our nine percent overriding royalty interest in the Prince Field to subsidiaries of El Paso Corporation. The results of operations for these assets have been accounted for as discontinued operations and have been excluded from continuing operations for all periods in our statements of income. Accordingly, the segment results in Note 14 reflect neither the results of operations for the Prince assets nor the related net assets held for sale. The Prince TLP was previously included in the Platform services segment and related royalty interest was included in the Other segment. Included in income from discontinued operations for the years ended December 31, 2002 and 2001 were revenues of \$7.8 million and \$8.8 million attributable to these disposed assets. We did not recognize any revenues related to the Prince assets during the year ended December 31, 2000, since these assets were not placed in service until September 2001.

The assets and liabilities related to the Prince assets disposition consist of the following:

	De	cember 31, 2001
	(In	thousands)
Property, plant and equipment	\$	189,432
Accumulated depreciation		(3,872)
Assets held for sale, net		185,560
Unamortized debt issue cost		1,091
Argo term loan		(95,000)
Accrued interest on Argo term loan		(703)
Net assets related to the Prince assets disposition	\$	90,948

In April 2002, we sold the Prince assets for \$190 million and recognized a gain on the sale of \$0.4 million during 2002. In conjunction with this transaction, we repaid the related outstanding \$95 million principal balance under our Argo term loan.

Deepwater Holdings L.L.C. and Chaco Transaction

In October 2001, we acquired the remaining 50 percent interest that we did not already own in Deepwater Holdings for approximately \$81 million, consisting of \$26 million cash and \$55 million of assumed indebtedness, and at the acquisition date also repaid all of Deepwater Holdings \$110 million of indebtedness. HIOS and East Breaks became indirect wholly-owned assets through this transaction. In a separate transaction, we acquired the Chaco cryogenic natural gas processing plant for \$198.5 million. The total purchase price was composed of a payment of \$77 million to acquire the plant from the bank group that provided the financing for the construction of the facility and a payment of D relating to the processing capacity of the Chaco plant and dedication of natural gas gathered by El Paso Field Services to the Chaco plant. Under the terms of the processing agreement, we received a fixed fee for each dekatherm of natural gas that we processed at the Chaco plant, and we bore all costs associated with the plant's ownership and operations. El Paso Field Services personnel continued to operate the plant. In accordance with the original construction financing agreements, the Chaco plant was under an operating lease to El Paso Field Services. El Paso Field Services had the right to repurchase the Chaco Plant at the end of the lease term in October 2002 for approximately \$77 million. We funded both of these transactions by borrowing from our revolving credit facility. We accounted for these transactions as purchases and have assigned the purchase price to the net assets acquired based upon the estimated fair value of the net assets as of the acquisition date. The operating results associated with Deepwater Holdings are included in earnings from unconsolidated affiliates for the periods prior to October 2001. We have included the operating results of Deepwater Holdings and the Chaco plant in our consolidated financial statements from the acquisition date.

Since the Chaco transaction was an asset acquisition, we have assigned the total purchase price to property, plant and equipment and investment in processing agreement. Since the Deepwater Holdings transaction was an acquisition of additional interests in a business, we are providing summary information related to the acquisition of Deepwater Holdings in the following table (in thousands):

Fair value of assets acquired	\$	81,331
Cash acquired		5,386
Fair value of liabilities assumed	((60,917)
Net cash paid	\$	25,800

In connection with our acquisition of the San Juan assets in November 2002, the original terms of the processing, lease and operating agreements between the Chaco plant and El Paso Field Services, were terminated. The effect on our operation of the Chaco plant resulting from our acquisition of the San Juan assets is discussed above.

EPN Texas

In February 2001, we acquired EPN Texas from a subsidiary of El Paso Corporation for \$133 million. We funded the acquisition of these assets by borrowing from our revolving credit facility. These assets include more than 500 miles of NGL gathering and transportation pipelines. The NGL pipeline system gathers and transports unfractionated and fractionated products. We also acquired three fractionation plants with a capacity of approximately 96 MBbls/d. These plants fractionate NGL into ethane, propane, butane and natural gasoline products that are used by refineries and petrochemical plants along the Texas Gulf Coast. We accounted for the acquisition as a purchase and assigned the purchase price to the assets acquired based upon the estimated fair value of the assets as of the acquisition date. We have included the operating results of EPN Texas in our consolidated financial statements from the acquisition date.

The following selected unaudited pro forma information represents our consolidated results of operations on a pro forma basis for the twelve months ended December 31, 2001 and 2000, as if we acquired EPN Texas, the Chaco plant and the remaining 50 percent interest in Deepwater Holdings on January 1, 2000:

	2001		2000
	(In thousands, except per unit amounts)		
Operating revenues	\$ 269,681	\$	222,080
Operating income	\$ 101,406	\$	96,197
Net income allocated to limited partners	\$ 39,157	\$	15,790
Basic and diluted net income per unit	\$ 1.14	\$	0.54

Gulf of Mexico Assets

In accordance with an FTC order related to El Paso Corporation's merger with The Coastal Corporation, we, along with Deepwater Holdings, agreed to sell several of our offshore Gulf of Mexico assets to third parties in January 2001. Total consideration received for these assets was approximately \$163 million consisting of approximately \$109 million for the assets we sold and approximately \$54 million for the assets Deepwater Holdings sold. The offshore assets sold include interests in Stingray, UTOS, Nautilus, Manta Ray Offshore, Nemo, Tarpon, and the Green Canyon pipeline assets, as well as interests in two offshore platforms and one dehydration facility. We recognized net losses from the asset sales of approximately \$12 million, and Deepwater Holdings recognized losses of approximately \$21 million. Our share of Deepwater Holdings losses was approximately \$14 million, which has been reflected in earnings from unconsolidated affiliates in the accompanying statements of income.

As additional consideration for the above transactions, El Paso Corporation will make payments to us totaling \$29 million. These payments will be made in quarterly installments of \$2.25 million for three years beginning in 2001 and ending with a \$2 million payment in the first quarter of 2004. From this additional consideration, we realized income of approximately \$25 million in the first quarter of 2001, which has been reflected in other income in the accompanying statements of income.

Crystal Gas Storage

In August 2000, we acquired the salt dome natural gas storage businesses of Crystal Gas Storage, Inc., a subsidiary of El Paso Corporation, in exchange for \$170 million of Series B 10% Cumulative Redeemable Preference Units. We accounted for the acquisition as a purchase and assigned the purchase price to the assets and liabilities acquired based upon the estimated fair value of those assets and liabilities as of the acquisition date. We have included the operating results of Crystal Gas Storage, Inc. in our consolidated financial statements from the acquisition date. The following is summary information related to the acquisition (in thousands):

Fair value of assets acquired	\$170,573
Fair value of liabilities assumed	(573)
Preference units issued	\$170,000

El Paso Intrastate-Alabama Pipeline System

In March 2000, we acquired EPIA from a subsidiary of EI Paso Corporation for \$26.5 million in cash. We accounted for the acquisition as a purchase and assigned the purchase price to the assets and liabilities acquired based upon the estimated fair value of those assets and liabilities as of the acquisition date. We have included the operating results of EPIA in our consolidated financial statements from the acquisition date. The following is summary information related to the acquisition (in thousands):

Fair value of assets acquired	\$	28,261
Fair value of liabilities assumed	_	(1,785)
Net cash paid	\$	26,476

The following selected unaudited pro forma information represents our consolidated results of operations on a pro forma basis for the year ended December 31, 2000, assuming we acquired EPIA and the Crystal natural gas storage businesses on January 1, 2000:

	2000		
	(In thousands,		
	except per		
	unit	amounts)	
Operating revenues	\$	131,426	
Operating income	\$	45,171	
Net income allocated to limited partners	\$	1,887	
Basic and diluted net income per unit	\$	0.06	

3. Investments in Unconsolidated Affiliates

We hold investments in unconsolidated affiliates which are accounted for using the equity method of accounting. As of December 31, 2002, the carrying amount of our equity investments exceeded the underlying equity in net assets by approximately \$3.0 million, which is included in our Oil and NGL logistics segment. With our adoption of SFAS No. 142 on January 1, 2002, we no longer amortize this excess amount, refer to Note 1, Summary of Significant Accounting Policies, Goodwill and Other Intangible Assets. Summarized financial information for these investments is as follows:

As of or for the Year Ended December 31, 2002

			Deepwater	
	Coyote ^(a)	Poseidon	Gateway ^(b)	Total
		(In tho	usands)	
End of period ownership interest	50%	36%	50%	
Operating results data:				
Operating revenues	\$ 635	\$ 1,086,757	\$ -	
Crude oil purchases	_	1,032,496		
Gross margin	635	54,261	_	
Other income	2	26,695	20	
Operating expenses	(38)	(4,691)	_	
Depreciation	(110)	(8,356)	_	
Other expenses	(75)	(6,923)	(234)	
Net income (loss)	\$ 414	\$ 60,986	\$ (214)	
Our share:				
Allocated income (loss)	\$ 207	\$ 21,955	\$ (107)	
Adjustments ^(c)	(13)	(8,510)	107	
Earnings from unconsolidated affiliate	\$ 194	\$ 13,445	\$ —	\$ 13,639
Allocated distributions	\$ 2,000	\$ 15,804	\$ -	\$ 17,804
Financial position data:				
Current assets	\$ 1,575	\$ 152,784	\$ 10,745	
Noncurrent assets	33,349	218,463	110,309	
Current liabilities	34,559	119,974	28,268	
Noncurrent liabilities	_	148,000	27,000	

⁽a) We acquired an interest in Coyote Gas Treating, L.L.C. in November 2002 as part of the San Juan assets acquisition.

⁽b) In June 2002, we formed Deepwater Gateway, L.L.C., a 50/50 joint venture with Cal Dive International, Inc., to construct and install the Marco Polo TLP. Also in August 2002, Deepwater Gateway obtained a project finance loan to fund a substantial portion of the cost to construct the Marco Polo TLP. For further discussion of this project loan, see Note 6, Financing Transactions. Deepwater Gateway, L.L.C. is a development stage company; therefore there are no operating revenues or operating expenses to provide operational results. Since Deepwater Gateway's formation in 2002, it has incurred organizational expenses and received interest income.

⁽e) We recorded adjustments primarily for differences from estimated year end earnings reported in our Annual Report on our Form 10-K and actual earnings recorded in the audited annual reports of our unconsolidated affiliates. The adjustment for Poseidon primarily represents the receipt of proceeds from a favorable litigation related to the January 2000 pipeline rupture.

	As of or for the fear Ended December 31, 2001							2001	
	Deepwater				Divested				
	Holdings ^(a)		ı	Poseidon		Investments(b		Other(c)	Total
					(In	thousand	s)		
End of period ownership									
interest	_	100%	_	36%	_		_	50%	
Operating results data:									
Operating revenues	\$	40,933	\$	1,196,840	\$	1,982	,	\$ 145	
Crude oil purchases				1,126,439	_		_		
Gross margin		40,933		70,401		1,982		145	
Other income (loss)		_		394		(85)		_	
Operating expenses		(16,740)		(1,586)		(590)		(73)	
Depreciation		(8,899)		(10,552)		(953)		_	
Other (expenses) income		(5,868)		(7,668)		222		(22)	
Loss on sale of assets		(21,453)			_		_		
Net income (loss)	\$	(12,027)	\$	50,989	\$	576		\$ 50	
Our share:									
Allocated income (loss) ^(d)	\$	(9,925)	\$	18,356	\$	148	,	\$ 25	
Adjustments ^(e)	_			(146)	_	(9)	_		
Earnings (loss) from unconsolidated									
affiliates	\$	(9,925)	\$	18,210	\$	139		\$ 25	\$ 8,449
Allocated distributions	\$	12,850	\$	22,212	\$	_		\$ -	\$ 35,062
Financial position data:							_		
Current assets			\$	91,367			(\$ 177	
Noncurrent assets				226,570				_	
Current liabilities				80,365				33	
Noncurrent liabilities				150,000				_	

In January 2001, Deepwater Holdings sold its Stingray and West Cameron subsidiaries. Deepwater Holdings sold its interest in its UTOS subsidiary in April 2001. In October 2001, we acquired the remaining 50 percent of Deepwater Holdings and as a result of this transaction, on a going forward basis Deepwater Holdings is consolidated in our financial statements. The information presented for Deepwater Holdings as an equity investment is through October 18, 2001.

⁽b) Divested Investments contains Manta Ray Offshore Gathering Company, L.L.C. and Nautilus Pipeline Company L.L.C. In January 2001, we sold our 25.67 percent interest in Manta Ray Offshore and our 25.67 percent interest in Nautilus.

⁽c) Through October 2001 this company processed gas for Deepwater Holdings' Stingray subsidiary. This agreement was terminated in October 2001, and as of this date there are no operations related to this investment.

The income (loss) from Deepwater Holdings is not allocated proportionately with our ownership percentage because the capital contributed by us was a larger amount of the total capital at the time of formation. Therefore, we were allocated a larger amount of amortization of Deepwater Holdings' excess purchase price of its investments. Also, we were allocated a larger portion of Deepwater Holdings' \$21 million loss incurred in 2001 due to the sale of Stingray, UTOS, and the West Cameron dehydration facility. Our total share of the losses relating to these sales was approximately \$14 million.

⁽e) We recorded adjustments primarily for differences from estimated year end earnings reported in our Annual Report on Form 10-K and actual earnings reported in the audited annual reports of our unconsolidated affiliates.

As of or for the Year Ended December 31, 2000

	_			01 101 1110	.ou.	<u></u>		JO: J :, _ J	-	
	D	eepwater	Divested							
	ŀ	Holdings	P	oseidon	Inve	stments(a)	(Other		Total
					(In thousands)					
End of period ownership interest		50%		36%		25.67%		50%		
Operating results data:	_				_					
Operating revenues	\$	67,122	\$	1,466,086	\$	26,478	\$	110		
Crude oil purchases				1,402,721						
Gross margin		67,122		63,365		26,478		110		
Other income		532		639		2,301		_		
Operating expenses		(25,279)		(22,605)		(5,205)		(51)		
Depreciation		(18,138)		(10,754)		(10,363)		_		
Other expenses		(10,711)		(11,683)		(432)		(19)		
Net income	\$	13,526	\$	18,962	\$	12,779	\$	40		
Our share:					=					
Allocated income	\$	6,763	\$	6,826	\$	3,281	\$	20		
Adjustments ^(b)	_	507		5,892		(358)				
Earnings from unconsolidated										
affiliates	\$	7,270	\$	12,718	\$	2,923	\$	20	\$	22,931
Allocated distributions	\$	13,550	\$	13,532	\$	6,878	\$		\$	33,960
Financial position data:	_				=				_	
Current assets	\$	46,128	\$	125,325	\$	4,375	\$	111		
Noncurrent assets		237,416		239,030		247,554		_		
Current liabilities		39,962		264,776		1,423		27		
Noncurrent liabilities		166,517		1,297		_		_		

⁽ii) Divested Investments contains Manta Ray Offshore Gathering Company, L.L.C. and Nautilus Pipeline Company L.L.C. In January 2001, we sold our 25.67 percent interest in Manta Ray Offshore and our 25.67 percent interest in Nautilus.

⁽b) We recorded adjustments primarily for differences from estimated year end earnings reported in our Annual Report on Form 10-K and actual earnings reported in the audited annual reports of our unconsolidated affiliates, and for purchase price adjustments under APB Opinion No. 16, "Business Combinations." The adjustment for Poseidon primarily represents the receipt or expected receipt of insurance proceeds to offset our share of the repair costs related to the January 2000 pipeline rupture.

4. Property, Plant and Equipment

Our property, plant and equipment consisted of the following:

	December 31,				
		2002		2001	
	(In thousands)				
Property, plant and equipment, at cost					
Pipelines	\$	2,317,503	\$	856,335	
Platforms and facilities		128,582		125,546	
Processing plants		300,897		138,090	
Oil and natural gas properties		127,975		125,665	
Storage facilities		331,562		156,800	
Construction work-in-progress	_	177,964		99,667	
		3,384,483		1,502,103	
Less accumulated depreciation, depletion and amortization		659,545		584,236	
Total property, plant and equipment, net	\$	2,724,938	\$	917,867	

Due to the sale of our interest in the Manta Ray Offshore system in January 2001, we lost a primary connecting point to our Manta Ray pipeline. As a result, we abandoned the Manta Ray pipeline and recorded an impairment of approximately \$3.9 million in the first quarter of 2001 which is reflected in the Natural gas pipelines and plants segment.

5. Investment in Processing Agreement

As part of our October 2001 Chaco transaction, we paid \$121.5 million to El Paso Field Services for a 20-year fee-based processing agreement. As a result of the San Juan acquisition in November 2002, we now own the gathering system and related facilities previously owned by El Paso Field Services, including the rights of El Paso Field Services under the arrangements relating to the Chaco plant. Prior to this acquisition, our investment in the processing agreement was being amortized on a straight-line basis over the life of the agreement and we recorded amortization expense of \$5.6 million in 2002 and \$1.5 million in 2001 related to this asset. Under the processing agreement, all previously uncommitted volumes on El Paso Field Services' San Juan Gathering System were dedicated to the Chaco plant. As part of the agreement, natural gas delivered to the Chaco plant by El Paso Field Services had a processing priority over other natural gas.

6. Financing Transactions

In October 2002, we amended the terms of our \$600 million revolving credit facility and the EPN Holding term credit facility in connection with our entering into the senior secured term loan. The modifications included, among other things, (1) entering into a new \$160 million senior secured term loan maturing in 2007 as a term component of our revolving credit facility, which we collectively refer to as our credit facility; (2) designating the EPN Holding term credit facility as "senior secured" indebtedness, in addition to our credit facility which is cross-collateralized on an equal basis with all of the collateral currently pledged under our credit facility and the EPN Holding term credit facility; (3) aligning, effectively, the covenants in our credit facility and the EPN Holding term credit facility, including eliminating the restrictions for distributing cash out of EPN Holding; and (4) terminating the \$25 million revolving credit facility that was formerly part of the EPN Holding term credit facility.

In November 2002, we further amended our credit facility and the EPN Holding term credit facility in connection with our borrowing of \$237.5 million under the senior secured acquisition term loan to modify the interest rates the facilities bear. The modified interest rate we are charged under the terms of the amendment will remain in effect until the senior secured acquisition term loan is repaid in full. Under the amended terms of these agreements, the loans bear interest at our option at either (i) 2.25% plus a variable base rate (equal to the greater of the prime rate as determined by JP Morgan Chase Bank, the federal funds rate plus 0.5% or the Certificate of Deposit (CD) rate as determined by JP Morgan Chase Bank plus 1.00%); or (ii) LIBOR plus 3.50%. Our credit facility, the EPN Holding term credit facility, senior secured term loan and the senior secured acquisition term loan are discussed below.

Credit Facility

Revolving Credit Facility

As of December 31, 2002, we had \$491 million outstanding with an average interest rate of 5.14% under our \$600 million revolving credit facility with the total unused amount available. The applicable rates on our revolving credit facility will revert to the historical rate schedule at LIBOR plus rates ranging from 0.875% to 2.50% or one of the variable base rates described above plus rates ranging from 0.0% to 1.50% following repayment of the \$237.5 million senior secured acquisition term loan, subject to our meeting certain ratios and attaining certain ratings as set forth in our credit facility. Our interest rate is contingent upon our leverage ratio, as defined in our credit facility, and ratings we are assigned by S&P or Moody's on our long-term unsecured debt. The interest rate we are charged would increase by 0.50% if the credit ratings on our senior unsecured debt are decreased, or, alternatively, would decrease by 0.25% if these ratings are increased or our leverage ratio improves. We pay commitment fees on the unused portion of our revolving credit facility at rates that vary from 0.25% to 0.50% per year. The revolving credit facility matures in May 2004, is guaranteed by us and all of our subsidiaries, except for our unrestricted subsidiaries (Matagorda Island Area Gathering System, Arizona Gas Storage, L.L.C. and EPN Arizona Gas, L.L.C.), El Paso Energy Partners Finance Corporation and our general partner, and is cross-collateralized with our other credit facilities by substantially all of our assets (excluding our unrestricted subsidiaries) and our general partner's general and administrative services agreement. The covenants and events of default governing the revolving credit facility are described under Credit Facilities Covenants.

Senior Secured Term Loan

In October 2002, in connection with the amendment of our credit facilities discussed above, we obtained a \$160 million senior secured term loan with a syndicate of lenders which we used to temporarily reduce indebtedness under our \$600 million revolving credit facility. We may elect that all or a portion of the senior secured term loan bear interest at either 2.25% plus a variable base rate (equal to the greater of the prime rate as determined by JP Morgan Chase Bank, the federal funds rate plus 0.5% or the CD rate as determined by JP Morgan Chase Bank plus 1%); or LIBOR plus 3.5%. We may, at our option, make prepayments in amounts not less than \$5 million. The senior secured term loan is payable in semi-annual installments of \$2.5 million in April and October of each year beginning April 2003 for the first nine installments and the remaining balance at maturity in October 2007. The senior secured term loan is guaranteed by us, all of our subsidiaries (other than our unrestricted subsidiaries) and our general partner; and is cross-collateralized with our credit facility, the EPN Holding term credit facility, and our senior secured acquisition term loan by substantially all of our assets (excluding our unrestricted subsidiaries) and by our general partner's general and administrative services agreement. As of December 2002 we had \$160 million outstanding with an average interest rate of 5.22%. The covenants and events of default governing this loan are described under Credit Facilities Covenants.

EPN Holding Term Credit Facility

In connection with our acquisition of the EPN Holding assets from El Paso Corporation in April 2002, EPN Holding entered into a \$560 million term credit facility with a group of commercial banks. The term credit facility provided a term loan (the EPN Holding term loan) of \$535 million to finance the acquisition of the EPN Holding assets, and a revolving credit facility (the EPN Holding revolving credit facility) of up to \$25 million to finance EPN Holding's working

capital. EPN Holding's obligations under the term credit facility are guaranteed by us, all of our subsidiaries (other than our unrestricted subsidiaries,), El Paso Energy Partners Finance Corporation and our general partner and is cross-collateralized with our other credit facilities by substantially all of our assets (excluding our unrestricted subsidiaries) and by our general partner's general and administrative services agreement. At the time of its acquisition, EPN Holding borrowed \$535 million (\$531 million, net of issuance costs) under this term loan and had \$25 million available under the EPN Holding revolving credit facility which we have subsequently terminated. The EPN Holding term loan matures in April 2005. We used net proceeds of approximately \$149 million from our April 2002 common unit offering, \$0.6 million contributed by our general partner to maintain its one percent capital account balance and \$225 million of the net proceeds from our May 2002 offering of 8 1/2% Senior Subordinated Notes to reduce indebtedness under the term loan. As of December 31, 2002, the outstanding balance under the EPN Holding term credit facility was \$160 million with an average interest rate of 4.92%. Following our repayment of the senior secured acquisition term loan, the interest rate we are charged on balances outstanding under the EPN Holding term credit facility will revert to the historical rate schedule at LIBOR plus rates ranging from 1.75% to 2.50% or one of the variable base rates described above plus rates ranging from 0.50% to 1.25%, subject to our meeting certain ratios set forth in the EPN Holding term credit facility. The interest rate we are charged would increase by 0.25% if our leverage ratio deteriorates to 5.00 to 1.00 or greater, or would decrease by 0.25% if our leverage ratio improves to 4.00 to 1.00 or less. The covenants and events of default governing this credit facility are described under Credit Facilities Covenants.

Senior Secured Acquisition Term Loan

As part of the San Juan assets acquisition, we entered into a \$237.5 million senior secured acquisition term loan to fund a portion of the \$766 million purchase price of the San Juan assets. The loan bears interest at our option at either (i) 2.25% plus a variable rate (equal to the greater of the prime rate as determined by JP Morgan Chase Bank, the federal funds rate plus .05% or the CD rate as determined by JP Morgan Chase Bank plus 1%); or (ii) LIBOR plus 3.5% and is subject to a grid based on our credit ratings. The interest rate we are charged on balances outstanding under the senior secured acquisition term loan is dependent on the ratings we are assigned by S&P and Moody's on our senior secured long-term bank debt. Our interest rate is increased by 1.00% when our senior secured long-term bank debt is rated below the higher of BB+ by S&P and Ba1 by Moody's. At December 31, 2002, we had \$237.5 million outstanding with an average interest rate of 4.95%. We repaid the senior secured acquisition term loan in March 2003 with proceeds from our issuance of \$300 million 8 1/2% Senior Subordinated Notes.

Credit Facilities Covenants

Our credit facility, the EPN Holding term credit facility and our senior secured acquisition term loan contain covenants that include restrictions on our and our subsidiaries' ability to incur additional indebtedness or liens, sell assets, make loans or investments, acquire or be acquired by other companies and amend some of our contracts, as well as requiring maintenance of certain financial ratios. Failure to comply with the provisions of any of these covenants could result in acceleration of our debt and other financial obligations and that of our subsidiaries and restrict our ability to make distributions to our unitholders. The financial covenants associated with these facilities are as follows:

- (a) Consolidated tangible net worth cannot be less than \$710.0 million plus 75 percent of the net proceeds we receive from future sales or issuance of any equity securities by us;
- (b) The ratio of consolidated EBITDA, as defined in our credit agreements, to consolidated interest expense cannot be less than 2.0 to 1.0;
- (c) The ratio of consolidated total senior indebtedness on the last day of any fiscal quarter to the consolidated EBITDA for the four quarters ending on the last day of the current quarter cannot exceed 3.25 to 1.0; and
- (d) The ratio of our consolidated total indebtedness on the last day of any fiscal quarter through December 31, 2003 to the consolidated EBITDA for the four quarters ending on the last day of the current quarter cannot exceed 5.25 to 1.0. The ratio of consolidated total indebtedness to consolidated EBITDA will decline to 5.0 to 1.0 beginning January 1, 2004.

Among other things, each credit agreement includes as an event of default the failure of El Paso Corporation and its subsidiaries to own more than 50 percent of our general partner unless our creditors agree otherwise. We are in compliance with the financial ratios and covenants contained in each of our credit facilities at December 31, 2002. We have available for use the entire \$109 million remaining under our revolving credit facility.

Senior Subordinated Notes

Each issue of our senior subordinated notes is subordinated in right of payment to all existing and future senior debt including our credit facility, the EPN Holding term credit facility and our senior secured acquisition term loan. Additionally, our subordinated notes include provisions that, among other things, restrict our and our subsidiaries ability to acquire assets, incur additional indebtedness or liens, sell assets, acquire or be acquired by other companies, and enter into sale and lease-back transactions unless we meet certain financial ratios and other specific conditions. These restrictive covenants will be suspended should our notes be rated Baa3 or higher by Moody's or BBB— or higher by S&P.

In November 2002, we issued \$200 million in aggregate principal amount of 10 5 /8% Senior Subordinated Notes. These notes bear interest of 10 5 /8% per year, payable semi-annually in June and December, and mature in December 2012. These notes were issued for \$198 million, net of discount of \$1.5 million to yield 10.75% (proceeds of \$194 million, net of issuance costs) which we used to fund a portion of the acquisition of the San Juan assets. These notes are subject to a registration rights agreement whereby, we are required to register these notes on Form S-4 with the SEC within 150 days of their issuance or under certain circumstances be subject to penalties of approximately \$10,000 per week until a registration statement is filed with the SEC and declared effective. On February 28, 2003, we filed a Form S-4 with the SEC, however, it has not been declared effective. We may, at our option, prior to December 1, 2005, redeem up to 33 percent of the originally issued aggregate principal amount of the notes at a redemption price of 110.625%. On or after December 1, 2007, we may redeem all or part of these notes at 105.313% of the principal amount.

In May 2002, we issued \$230 million in aggregate principal amount of 8 1/2% Senior Subordinated Notes. These notes bear interest of 8 1/2% per year, payable semi-annually in June and December, and mature June 2011. The Senior Subordinated Notes were issued for \$234.6 million (proceeds of approximately \$230 million, net of issuance costs). We used proceeds of \$225 million to reduce indebtedness under our EPN Holding term credit facility and the remainder for general partnership purposes. We may, at our option, prior to June 1, 2004, redeem up to 33 percent of the originally issued aggregate principal amount of the senior subordinated notes due June 2011, at a redemption price of 108.500%. On or after June 1, 2006, we may redeem all or part of these notes at 104.250% of the principal amount.

In May 2001, we issued \$250 million in aggregate principal amount of 8 ¹/₂% Senior Subordinated Notes. These notes bear interest at a rate of 8 ¹/₂% per year, payable semi-annually in June and December, and mature in June 2011. Proceeds of approximately \$243 million, net of issuance costs, were used to reduce indebtedness under our revolving credit facility. We may, at our option, prior to June 1, 2004, redeem up to 33 percent of the originally issued aggregate principal amount of the senior subordinated notes due June 2011, at a redemption price of 108.500%. On or after June 1, 2006, we may redeem all or part of these notes at 104.250% of the principal amount.

In May 1999, we issued \$175 million in aggregate principal amount of 10 3 /8% Senior Subordinated Notes. These notes bear interest at a rate of 10 3 /8% per year, payable semi-annually in June and December, and mature in June 2009. Proceeds of approximately \$169 million, net of issuance costs, were used to reduce indebtedness under our revolving credit facility. On or after June 1, 2004, we may redeem all or part of these notes at 105.188% of the principal amount.

Our subsidiaries, except El Paso Energy Partners Finance Corporation and our unrestricted subsidiaries, have guaranteed our obligations under all of the issuances of senior subordinated notes described above. In addition, we could be required to repurchase the senior subordinated notes if certain circumstances relating to change of control or

asset dispositions exist. We are currently in compliance with the financial ratios and covenants contained in each of our senior subordinated notes at December 31, 2002.

Argo Term Loan

This loan with a balance of \$95 million, including current maturities, at December 31, 2001, was repaid in full in April 2002, in connection with the EPN Holding asset acquisition.

Other Credit Facilities

Poseidon Oil Pipeline Company, L.L.C., an unconsolidated affiliate in which we have a 36 percent joint venture ownership interest, is party to a \$185 million credit agreement under which it has outstanding obligations that may restrict its ability to pay distributions to its owners.

In January 2002, Poseidon entered into a two-year interest rate swap agreement to fix the variable LIBOR based interest rate on \$75 million of the \$148 million outstanding under its credit facility at 3.49% through January 2004. Poseidon, under its credit facility, currently pays an additional 1.50% over the LIBOR rate resulting in an effective interest rate of 4.99% on the hedged notional amount. The interest rates Poseidon is charged on balances outstanding under its credit facility is dependent on their leverage ratio as defined in the Poseidon credit facility. Poseidon's interest rate at December 31, 2002 was LIBOR plus 1.50% for Eurodollar loans and a variable base rate equal to the greater of the prime rate or 0.50% plus the federal funds rate (as those terms are defined in the Poseidon credit agreement) plus 0.50% for Base Rate loans. Poseidon's interest rates will decrease by 0.25% if their leverage ratio declines below 2.00 to 1.00 or by 0.50% if their leverage ratio declines to 1.00 to 1.00 or less. Additionally, Poseidon pays commitment fees on the unused portion of the credit facility at rates that vary from 0.25% to 0.375%. This credit agreement requires Poseidon to maintain a debt service reserve equal to two quarters interest and is collateralized by substantially all of Poseidon's assets. As of December 31, 2002, the remaining \$73 million was at an average interest rate of 3.38%.

Poseidon's credit agreement contains covenants such as restrictions on debt levels, restrictions on liens collateralizing debt and guarantees, restrictions on mergers and on the sales of assets and dividend restrictions. A breach of any of these covenants could result in acceleration of Poseidon's debt and other financial obligations.

Under the Poseidon revolving credit facility, the financial debt covenants are:

- (a) Poseidon must maintain consolidated tangible net worth in an amount not less than \$75 million plus 100% of the net cash proceeds from the issuance by Poseidon of equity securities of any kind;
- (b) the ratio of Poseidon's EBITDA, as defined in Poseidon's credit agreement, to interest expense paid or accrued during the four quarters ending on the last day of the current quarter must be at least 2.50 to 1.00; and
- (c) the ratio of total indebtedness of Poseidon to EBITDA for the four quarters ending on the last day of the current quarter shall not exceed 3.00 to 1.00.

Poseidon was in compliance with the above covenants as of December 31, 2002.

In August 2002, Deepwater Gateway, our joint venture that is constructing the Marco Polo TLP, obtained a \$155 million project finance loan from a group of commercial lenders to finance a substantial portion of the cost to construct the Marco Polo TLP and related facilities. Deepwater Gateway may elect that all or a portion of the project finance loan bear interest at either i) LIBOR plus 1.75% or ii) an alternate base rate (equal to the greater of the prime rate, the base CD rate plus 1% or the federal funds rate plus 0.5%, as those terms are defined in the project finance loan agreement) plus 0.75%. Deepwater Gateway must also pay commitment fees of 0.375% per year on the unused portion of the project finance loan. The loan is collateralized by substantially all of Deepwater Gateway's assets.

If Deepwater Gateway defaults on its payment obligations under the project finance loan, we would be required to pay to the lenders all distributions we or any of our subsidiaries have received from Deepwater Gateway up to \$22.5 million. As of December 31, 2002, Deepwater Gateway had \$27 million outstanding under the project finance loan at an average interest rate of 3.38% and had not paid us or any of our subsidiaries any distributions.

This project finance loan will mature in July 2004 unless construction is completed before that time and Deepwater Gateway meets other specified conditions, in which case the project finance loan will convert into a term loan with a final maturity date of July 2009. Upon conversion of the project finance loan to a term loan, Deepwater Gateway will be required to maintain a debt service reserve of not less than the projected principal, interest and fees due on the term loan for the immediately succeeding six month period. In addition, Deepwater Gateway is prohibited from making distributions until the project finance loan has been repaid or is converted.

Debt Maturity Table

Aggregate maturities of the principal amounts of long-term debt and other financing obligations for the next 5 years and in total thereafter are as follows (in thousands):

\$ 5,000
733,500
165,000
5,000
140,000
855,000
\$ 1,903,500

In March 2003, we issued \$300 million in aggregate principal amount of 8 ¹/₂% Senior Subordinated Notes. These notes bear interest of 8 ¹/₂% per year, payable semi-annually in June and December and matures in June 2010. These notes were issued at par and were used to repay the \$238 million senior secured acquisition term loan and temporarily reduce our revolving credit facility.

Interest Expense

We recognized the interest cost incurred in connection with our financing transactions as follows for each of the years ended:

	2002	2001		2000
		(In thousands)		
Interest expense incurred	\$ 89,956	\$ 54,885	\$	51,076
Interest capitalized	(5,571)	(11,755)		(4,005)
Net interest expense	84,385	43,130		47,071
Less: Interest expense on discontinued operations	891	1,588	_	251
Net interest expense on continuing operations	\$ 83,494	\$ 41,542	\$_	46,820
			_	

7. Financial Instruments

Fair Value of Financial Instruments

The carrying amounts and estimated fair values of our financial instruments at December 31 are as follows:

	2002			2001				
	Carrying			C	arrying			
	A	mount	Fa	ir Value	Α	mount	Fa	ir Value
	(In m			illions)			
Liabilities:								
Revolving credit facility	\$	491.0	\$	491.0	\$	300.0	\$	300.0
EPN Holding term credit facility		160.0		160.0		_		_
Senior secured term loan		160.0		160.0		_		_
Senior secured acquisition term loan		237.5		237.5		_		_
Limited recourse term loan		_		_		95.0		95.0
10 ³ /8% Senior Subordinated Notes		175.0		186.4		175.0		185.5
8 ¹ / ₂ % Senior Subordinated Notes		250.0		233.1		250.0		252.5
8 ¹ / ₂ % Senior Subordinated Notes		234.3		214.5		_		_
10 ⁵ /8% Senior Subordinated Notes		198.5		205.5		_		_
Non-trading derivative instruments								
Commodity swap and forward contracts	\$	4.7	\$	4.7	\$	1.3	\$	1.3

The notional amounts and terms of contracts held for purposes other than trading were as follows at December 31:

		200)2	2001				
	Notional			Not	ional			
	Volume			Vol	ume			
			Maximum			Maximum		
	Buy	Sell	Term in Years	Buy	Sell	Term in Years		
Commodity								
Natural Gas (MDth)	95	10,950	<1	765	_	<1		

As of December 31, 2002, and 2001, our carrying amounts of cash and cash equivalents, short-term borrowings, and trade receivables and payables are representative of fair value because of the short-term nature of these instruments. The fair value of long-term debt with variable interest rates approximates its carrying value because the variable interest rates on these loans reprice frequently to reflect currently available interest rates. We estimated the fair value of debt with fixed interest rates based on quoted market prices for the same or similar issues. We estimated the fair value of all derivative financial instruments from prices indicated for the same or similar commodity transactions for a specific index.

Credit Risk

Credit risk relates to the risk of loss that we would incur as a result of our customers' failure to pay. Our customers are concentrated in the energy sector, and the creditworthiness of several industry participants have been called into question. We maintain credit policies to minimize overall credit risk. We monitor our exposure to and determine, as appropriate, whether we should request prepayments, letters of credit or other collateral from our counterparties.

8. Partners' Capital

General

As of December 31, 2002, we had 44,030,314 common units outstanding. Common units totaling 32,356,069 are owned by the public, representing a 73.5 percent common unit interest in us. As of December 31, 2002, El Paso Corporation, through its subsidiaries, owned 11,674,245 common units, or 26.5 percent of our outstanding common units, all of our 125,392 Series B preference units (with a liquidation value of \$158 million), all of our 10,937,500 Series C units and our one percent general partner interest.

Offering of Common Units

In April 2002, we completed simultaneous offerings of 4,083,938 common units, which included a public offering of 3,000,000 common units and a private offering, at the same unit price, of 1,083,938 common units to our general partner (pursuant to our general partner's anti-dilution rights under our partnership agreement) as a transaction not involving a public offering. We used the net cash proceeds of approximately \$149 million to reduce indebtedness under EPN Holding's term credit facility. Also in April 2002, we issued in a private offering 159,497 common units at the then-current market price of \$37.74 per unit to a subsidiary of El Paso Corporation as partial consideration for our acquisition of the EPN Holding assets. In addition, our general partner contributed approximately \$0.6 million in cash to us in April 2002 in order to maintain its one percent capital account balance.

In October 2001, we completed simultaneous offerings of 5,627,070 common units, which included a public offering of 4,150,000 common units and a private offering, at the same unit price, of 1,477,070 common units to our general partner (pursuant to our general partner's anti-dilution rights under our partnership agreement) as a transaction not involving a public offering. We used the net cash proceeds of approximately \$212 million to redeem 44,608 of our Series B preference units for their liquidation value of \$50 million and to reduce the balance outstanding under our revolving credit facility. In addition, our general partner contributed \$2.1 million in cash to us in order to satisfy its one percent contribution requirement.

In March 2001, we completed a public offering of 2,250,000 common units. We used the net cash proceeds of \$66.6 million from the offering to reduce the balance outstanding under our revolving credit facility. In addition, our general partner contributed \$0.7 million to us in order to satisfy its one percent capital contribution requirement.

In July 2000, we completed a public offering of 4,600,000 common units. We used the net cash proceeds of \$101 million to reduce the balance outstanding under our revolving credit facility. In addition, our general partner contributed \$1.1 million to us in order to satisfy its one percent capital contribution requirement.

Conversion and Redemption of Preference Units

In May 1998, 1999 and 2000, we notified the holders of our publicly-held preference units of their opportunity to convert their preference units into an equal number of common units. Total preference units of 211,249 were converted to common units after the 90-day conversion period in 2000 and 78,450 preference units remained. In October 2000, we redeemed the remainder of these preference units for approximately \$0.8 million representing a cash price of \$10.25 per unit. For the converted units, we reallocated the partners' capital accounts in the conversion period to reflect these conversions of preference units into common units.

Series B Preference Units

In August 2000, we issued 170,000 Series B preference units with a value of \$170 million to acquire the Petal and Hattiesburg natural gas storage businesses. In October 2001, we redeemed 44,608 of the Series B preference units for \$50 million liquidation value including accrued distributions of approximately \$5.4 million, bringing the total number of units outstanding to 125,392. As of December 31, 2002, the liquidation value of the outstanding Series B preference units was approximately \$158 million. These preference units are non-voting and have rights to income allocations on a

cumulative basis, compounded semi-annually at an annual rate of 10%. We are not obligated to pay cash distributions on these units until 2010. After September 2010, the rate will increase to 12% and preference income allocation after 2010 will be required to be paid on a current basis; accordingly, after September 2010, we will not be able to make distributions on our common units unless all unpaid accruals occurring after September 2010 on our then-outstanding Series B preference units have been paid. These preference units contain no mandatory redemption obligation, but may be redeemed at our option at any time. If our capital was ever liquidated, then these Series B preference units would have priority after our general partner, but before our outstanding common unitholders.

Series C Units

In November 2002, we issued to a subsidiary of El Paso Corporation 10,937,500 of Series C units at a price of \$32 per unit, \$350 million in the aggregate, as part of our consideration paid for the San Juan assets. The issuance of the Series C units was an exempt transaction under Section 4(2) of the Securities Act of 1993 as a transaction not involving a public offering. The Series C units are similar to our existing common units, except that the Series C units are non-voting. After April 30, 2003, the holder of the Series C units will have the right to cause us to propose a vote of our common unitholders as to whether the Series C units should be converted into common units. If our common unitholders approve the conversion, then each Series C unit can convert into a common unit. If our common unitholders do not approve the conversion within 120 days after the vote is requested, then the distribution rate for the Series C units will increase to 105 percent of the common unit distribution rate in effect from time to time. Thereafter, the Series C unit distribution rate will increase on April 30, 2004, to 110 percent of the common unit distribution rate and on April 30, 2005, to 115 percent of the common unit distribution rate. In addition, our general partner contributed \$3.5 million to us in order to satisfy its one percent capital contribution requirement.

Cash Distributions

We make quarterly distributions of 100 percent of our available cash, as defined in the partnership agreement, to our unitholders and to our general partner. Available cash generally consists of all cash receipts plus reductions in reserves less all cash disbursements and net additions to reserves. Our general partner has broad discretion to establish cash reserves for any proper partnership purpose. These can include cash reserves for future capital and maintenance expenditures, reserves to stabilize distributions of cash to the unitholders and our general partner, reserves to reduce debt, or, as necessary, reserves to comply with the terms of our agreements or obligations. Beginning in the fourth quarter of 2010, any unpaid accruals on our Series B preference units occurring after September 2010 will be currently payable and must be completely paid, prior to any distributions on our common units.

Cash distributions on common units, Series C units and to our general partner are discretionary in nature and are not entitled to arrearages of minimum quarterly distributions. The following table reflects our per unit cash distributions to our common unitholders and the total incentive distributions paid to our general partner during the year ended December 31, 2002:

	Common		Common		General	
Month Paid ⁽¹⁾		Unit	Unit	holders	Partner	
	(F	Per unit)	(In m		ions)	
February	\$	0.625	\$	24.8	\$	8.9
May	\$	0.650	\$	28.6	\$	10.9
August	\$	0.650	\$	28.6	\$	10.9
November	\$	0.675	\$	29.7	\$	12.0

⁽¹⁾ Our Series C units are not included in the above table since they did not receive a distribution until February 2003.

In January 2003, we declared a cash distribution of \$0.675 per common and Series C unit, \$37.1 million in aggregate, which we paid on February 14, 2003. In addition, we paid distributions to our general partner of \$14.6 million in respect of its general partner interest. At the current distribution rates, our general partner receives approximately 29 percent of our total cash distributions for its role as our general partner.

Option Plans

In August 1998, we adopted the 1998 Omnibus Compensation Plan (Omnibus Plan) to provide our general partner with the ability to issue unit options to attract and retain the services of knowledgeable officers and key management personnel. Unit options to purchase a maximum of 3 million common units may be issued pursuant to the Omnibus Plan. Unit options granted to date pursuant to the Omnibus Plan are not immediately exercisable. For unit options granted in 2001, one-half of the unit options are considered vested and exercisable one year after the date of grant and the remaining one-half of the unit options are considered vested and exercisable one year after the first anniversary of the date of grant. These unit options expire ten years from such grant date, but shall be subject to earlier termination under certain circumstances. No grants of unit options were made in 2002.

In August 1998, we also adopted the 1998 Unit Option Plan for Non-Employee Directors (Director Plan) to provide our general partner with the ability to issue unit options to attract and retain the services of knowledgeable directors. Unit options and restricted units to purchase a maximum of 100,000 of our common units may be issued pursuant to the Director Plan. Under the Director Plan, each non-employee director receives a grant of 2,500 unit options upon initial election to the Board of Directors and an annual unit option grant of 2,000 unit options and, beginning in 2001, an annual restricted unit grant equal to the director's annual retainer (including Chairman's retainers, if applicable) divided by the fair market value of the common units on the grant date upon each re-election to the Board of Directors. Each unit option that is granted will vest immediately at the date of grant and will expire ten years from such date, but will be subject to earlier termination in the event that such non-employee director ceases to be a director of our general partner for any reason, in which case the unit options expire 36 months after such date except in the case of death, in which case the unit options expire 12 months after such date. Each director receiving a grant of restricted units is recorded as a unitholder and has all the rights of a unitholder with respect to such units, including the right to distributions on those units. The restricted units are nontransferable during the director's service on the Board of Directors. The restrictions on the restricted units will end and the director will receive one common unit for each restricted unit granted upon the director's termination. The Director Plan is administered by a management committee consisting of the Chairman of the Board of Directors of the general partner and such other senior officers of our general partner or its affiliates as the Chairman may designate. Restricted units awards representing 5,429 and 4,090 were granted during 2002 and 2001 with a grant price of \$32.23 and \$33.00 per unit. No restricted units were granted in 2000. As of December 31, 2002, 7,066 restricted units were outstanding. The value of these units is determined based on the fair market value on the grant date and this cost is amortized to compensation expense over the period of service, which we have estimated to be one year.

We have reflected the issuance of the restricted units as deferred compensation and as an increase in common units. This deferred compensation was approximately \$175 thousand and \$135 thousand in 2002 and 2001. Our 2001 deferred compensation is fully amortized. The unamortized amount of our total deferred compensation as of December 31, 2002, was approximately \$1.2 million.

The following table summarizes activity under the Omnibus Plan and Director Plan (excluding our restricted units) as of and for the years ended December 31, 2002, 2001 and 2000.

	200	02	200	01	2000		
		Weighted	Weighted			Weighted	
	# Units of Averag		# Units of	Average	# Units of	Average	
	Underlying	erlying Exercise Underlying		Exercise	Exercise Underlying		
	Options	Price	Options	ns Price Opt		Price	
Outstanding at beginning of							
year	1,614,500	\$ 32.09	925,500	\$ 27.15	937,500	\$ 27.16	
Granted	8,000	32.23	1,016,500	35.00	3,000	25.56	
Exercised	42,500	27.19	307,500	27.17	_	_	
Forfeited	_	_	_	_	7,500	27.19	
Canceled	30,000	34.99	20,000	27.19	7,500	27.19	
Outstanding at end of year	1,550,000	\$ 32.17	1,614,500	\$ 32.09	925,500	\$ 27.15	
Options exercisable at end of							
year	1,068,500	\$ 30.88	606,500	\$ 27.22	925,500	\$ 27.15	

The fair value of each unit option granted is estimated on the date of grant using the Black-Scholes option-pricing model with the following weighted average assumptions:

Assumption	2002	2001	2000
Expected term in years	8	8	8
Expected volatility	31.05%	27.50%	27.97%
Expected distributions	8.09%	9.55%	9.35%
Risk-free interest rate	3.24%	5.05%	5.35%

The Black-Scholes weighted average fair value of options granted during 2002, 2001, and 2000 was \$3.71, \$2.62, and \$2.63 per unit option, respectively.

Options outstanding as of December 31, 2002, are summarized below:

Options Outstanding						Options Exercisable			
Weighted Average Weighted							eighted		
Range of	Number	Remaining	Average		Number	A۱	erage		
Exercise Prices	Outstanding	Contractual Life	Exer	cise Price	Exercisable	Exer	cise Price		
\$19.86 to \$27.80	555,500	5.6	\$	27.18	555,500	\$	27.18		
\$27.80 to \$39.72	994,500	8.8	\$	34.95	513,000	\$	34.91		
\$19.86 to \$39.72	1,550,000	7.5	\$	32.17	1,068,500	\$	30.88		

9. Related Party Transactions

The majority of our related party transactions are with affiliates of our general partner. Under an agreement that was in place before an indirect subsidiary of El Paso Corporation purchased our general partner, an affiliate our general partner was obligated to provide individuals to perform the day to day financial, administrative, accounting and operational functions for us. As our activities increased, the fee for such services has also increased. Further, we provide services to various El Paso subsidiaries and, in turn, they provide us services. In addition, we have acquired a number of assets from subsidiaries of El Paso Corporation.

The following table provides summary data for the income statement impacts of our transactions with related parties for the years ended December 31:

	2002	2001	2000
		(In thousands)	
Revenues received from related parties:			
Natural gas pipelines and plants	\$ 159,608	\$ 20,710	\$ 9,356
Oil and NGL Logistics	26,288	25,249	_
Platform services ⁽¹⁾	_	35	146
Natural gas storage	3,016	2,325	1,268
Other ⁽¹⁾	9,809	5,676	15,722
	\$ 198,721	\$ 53,995	\$ 26,492
Expenses paid to related parties:			
Purchased natural gas costs	\$ 22,784	\$ 34,768	\$ 16,751
Operation and maintenance	60,458	33,721	22,817
	\$ 83,242	\$ 68,489	\$ 39,568
Reimbursements received from related parties:			
Operation and maintenance	\$ 2,100	\$ 11,499 ======	\$ 20,543

⁽¹⁾ In addition to revenues from continuing operations reflected above, we also received revenues from related parties in 2002 and 2001 of \$6.8 million and \$8.2 million for our Prince TLP and \$1.0 million and \$0.7 million for our 9 percent overriding royalty interest which are included in income from discontinued operations on our income statements.

For the years ended December 31, 2002, 2001 and 2000, revenues received from related parties consisted of approximately 42%, 28% and 24% of our revenue from continuing operations.

The following table provides summary data categorized by our related parties for the years ended December 31:

	2002	2001	2000
		(In thousands)
Revenues received from related parties:			
El Paso Corporation			
El Paso Merchant Energy North America Company	\$ 92,675	\$ 16,433	\$ 21,832
El Paso Production Company(1)	9,054	4,230	4,303
Southern Natural Gas Company	112	277	155
Tennessee Gas Pipeline Company	_	638	56
El Paso Field Services	96,880	32,382	_
Unconsolidated Subsidiaries			
Manta Ray Offshore ⁽²⁾		35	146
	\$ 198,721	\$ 53,995	\$ 26,492
Purchased natural gas costs paid to related parties:			
El Paso Corporation			
El Paso Merchant Energy North America Company	\$ 19,226	\$ 28,169	\$ 14,454
El Paso Production Company	2,251	6,412	2,160
Southern Natural Gas Company	245	187	137
Tennessee Gas Pipeline Company	70	_	_
El Paso Field Services	950	_	_
El Paso Natural Gas Company	42		
	\$ 22,784	\$ 34,768	\$ 16,751
Operating expenses paid to related parties:			
El Paso Corporation			
El Paso Field Services	\$ 60,000	\$ 33,187	\$ 22,265
Unconsolidated Subsidiaries			
Poseidon Oil Pipeline Company	458	534	552
	\$ 60,458	\$ 33,721	\$ 22,817
Reimbursements received from related parties:			
Unconsolidated Subsidiaries			
Deepwater Holdings ⁽³⁾	\$ -	\$ 9,399	\$ 20,344
Poseidon Oil Pipeline Company	2,100	2,100	_
Manta Ray Offshore ⁽²⁾			199
	\$ 2,100	\$ 11,499	\$ 20,543

⁽¹⁾ In addition to revenues from continuing operations from El Paso Production Company reflected above, during 2002 and 2001 we also received revenues of \$7.8 million and \$8.9 million from El Paso Production Company which are included in income from discontinued operations in our income statements.

⁽²⁾ We sold our interest in Manta Ray Offshore in January 2001 in connection with El Paso Corporation's merger with the Coastal Corporation.

In January 2001, Deepwater Holdings sold its Stingray and West Cameron subsidiaries. In April 2001, Deepwater Holdings sold its UTOS subsidiary. In October 2001, we acquired the remaining 50 percent of Deepwater Holdings, and as a result of this transaction, on a going forward basis, Deepwater Holdings is consolidated in our financial statements and our agreement with Deepwater Holdings terminated.

Revenues received from related parties

EPN Holding Assets. Our revenues from related parties increased in 2002 as a result of our EPN Holding transaction in which we acquired gathering, transportation and processing contracts with affiliates of our general partner. For the year ended December 31, 2002, we received \$68.9 million from El Paso Merchant Energy North America Company, \$35.8 million from El Paso Field Services and \$4.0 million from El Paso Production Company.

EPN Texas. In connection with our acquisition of EPN Texas in February 2001, we entered into a 20-year fee-based transportation and fractionation agreement with El Paso Field Services. Pursuant to this agreement, we receive a fixed fee for each barrel of NGL transported and fractionated by our facilities. Approximately 25 percent of our per barrel fee is escalated annually for increases in inflation. For the years ended December 31, 2002 and 2001, we received revenue of approximately \$26.0 million and \$25.2 million related to this agreement.

Chaco processing plant. In connection with our Chaco transaction in October 2001, we entered into a 20-year fee-based processing agreement with El Paso Field Services. Pursuant to this agreement, we receive a fixed fee for each dekatherm of natural gas that we process at the Chaco plant. For the years ended December 31, 2002 and 2001, we received revenue of \$29.6 million and \$6.5 million related to this agreement. In accordance with the original construction financing agreements, the Chaco plant is under an operating lease to El Paso Field Services. For the years ended December 31, 2002 and 2001, we received \$1.8 million and \$0.6 million related to this lease. As a result of the San Juan asset acquisition, the processing agreement and the operating lease were terminated.

Storage facilities. With the April 2002 acquisition of the EPN Holding assets, we purchased contracts held by Wilson Storage with El Paso Merchant Energy North America Company. For the year ended December 31, 2002 we received approximately \$2.9 million from El Paso Merchant Energy North America Company for natural gas storage fees. El Paso Merchant Energy North America Company and Tennessee Gas Pipeline Company use our Petal and Hattiesburg storage facilities from time to time. For the years ended December 31, 2002, 2001, and the four months ended December 31, 2000 we received approximately \$0.1 million, \$1.6 million and \$1.2 million from El Paso Merchant Energy North America Company for natural gas storage fees. For the years ended December 31, 2001, and the four months ended December 31, 2000 we received approximately \$0.7 million and \$0.1 million from Tennessee Gas Pipeline Company.

Prince TLP. In September 2001, we placed our Prince TLP in service. Prior to April 1, 2002, we received a monthly demand charge of approximately \$1.9 million as well as processing fees from El Paso Production Company related to production on the Prince TLP. For the year ended December 31, 2002 and the four months ended December 31, 2001, we received \$6.8 million and \$8.2 million in platform revenue related to this agreement. In connection with our acquisition of the EPN Holding assets from El Paso Corporation, in April 2002 we sold our Prince TLP to subsidiaries of El Paso Corporation and these revenues are reflected in our income from discontinued operations.

Production fields. Through 2000 we had agreed to sell substantially all of our oil and natural gas production to El Paso Merchant Energy North America Company on a month to month basis. The agreement provided fees equal to two percent of the sales value of crude oil and condensate and \$0.015 per dekatherm of natural gas for marketing production. During the year ended December 31, 2000, oil and natural gas sales related to this agreement totaled approximately \$15.7 million. Beginning in the fourth quarter of 2000, we began selling our oil and natural gas directly to third parties and our oil and natural gas sales related to El Paso Merchant Energy North America Company were approximately \$9.8 million and \$5.7 million for years ended December 31, 2002 and 2001.

In October 1999, we farmed out our working interest in the Prince Field to El Paso Production Company. Under the terms of the farmout agreement, our net overriding royalty interest in the Prince Field increased to a weighted average of approximately nine percent. El Paso Production Company began production on the Prince Field in September 2001. For the year ended December 31, 2002 and the four months ended December 31, 2001, we recorded approximately

\$1.0 million and \$0.7 million in revenues related to our overriding royalty interest in the Prince Field. In connection with our acquisition of the EPN Holding assets from El Paso Corporation, in April 2002 we sold our 9 percent overriding royalty interest in the Prince Field to subsidiaries of El Paso Corporation and these revenues are reflected in our income from discontinued operations.

EPIA. In March 2000, we acquired EPIA. Several EI Paso Corporation subsidiaries buy and transport natural gas on our EPIA system. For the years ended December 31, 2002, 2001 and 2000, we received approximately \$6.8 million, \$8.3 million and \$4.9 million from EI Paso Merchant Energy North America Company. For the years ended December 31, 2002, 2001 and 2000, we received approximately \$4.5 million, \$4.2 million and \$4.3 million from EI Paso Production Company. For the years ended December 31, 2002, 2001 and 2000, we received approximately \$0.1 million, \$0.2 million and \$0.2 million from Southern Natural Gas Company.

HIOS. In October 2001, HIOS became a wholly-owned asset through our acquisition of the remaining 50 percent equity interest in Deepwater Holdings. HIOS is a natural gas transmission system that has entered into interruptible transportation agreements at a non-discounted rate of \$0.1244. For the year ended December 31, 2002 and approximately three months ended December 31, 2001, we received \$1.4 million and \$0.8 million from El Paso Merchant Energy. For the year ended December 31, 2002, we received \$0.6 million from El Paso Production Company.

Texas NGL assets. In connection with our acquisition of the San Juan assets in November, 2002, we entered into a 10-year transportation agreement with El Paso Field Services. Pursuant to this agreement, beginning January 1, 2003, we receive a fee of \$1.5 million per year for transportation on our NGL pipeline which extends from Corpus Christi to near Houston. In addition, we provide transportation, fractionation, storage and terminaling services to El Paso Field Services, as well as to various third parties, typically under agreements of one year term or less. We received approximately \$0.3 million in revenues from El Paso Field Services for the year ended December 31, 2002.

Other. In addition to the revenues discussed above, we received \$2.6 million from El Paso Merchant North America and \$3.3 million from El Paso Field Services during 2002 for additional gathering and processing services.

Unconsolidated Subsidiaries. For the years ended December 31, 2001 and 2000, we received approximately \$0.03 million and \$0.1 million from Manta Ray Offshore Gathering as platform access and processing fees related to our South Timbalier 292 platform and our Ship Shoal 332 platform. We sold our interest in Manta Ray Offshore in January 2001 in connection with El Paso's merger with the Coastal Corporation.

Expenses paid to related parties

Cost of natural gas. Our cost of natural gas paid to related parties increased in 2002 as a result of our EPN Holding transaction in which we acquired contracts with affiliates of our general partner. For the year ended December 31, 2002, our EPN Holding assets had cost of natural gas expenses of \$0.3 million for the Waha facility from El Paso Merchant Energy North America Company and \$0.4 million from El Paso Field Services relating to the EPGT gathering system. EPIA's purchases of natural gas include transactions with affiliates of our general partner. For the years ended December 31, 2002, 2001 and 2000, we had natural gas purchases of approximately \$18.9 million, \$28.2 million and \$14.4 million from El Paso Merchant Energy North America Company, \$2.3 million, \$6.4 million and \$2.2 million from El Paso Production Company and \$0.2 million, \$0.2 million and \$0.1 million from Southern Natural Gas Company. We also receive lease and throughput fees from El Paso Field Services for Hattiesburg and Anse La Butte. For the year ended December 31, 2002 we received \$0.5 million from El Paso Field Services related to these fees.

Operating Expenses. Substantially all of the individuals who perform the day-to-day financial, administrative, accounting and operational functions for us, as well as those who are responsible for directing and controlling us, are currently employed by El Paso Corporation. Under a general and administrative services agreement between

subsidiaries of El Paso Corporation and us, a fee of approximately \$0.8 million per month was charged to our general partner, and accordingly, to us, which is intended to approximate the amount of resources allocated by El Paso Corporation and its affiliates in providing various operational, financial, accounting and administrative services on behalf of our general partner and us. In April 2002, in connection with our acquisition of EPN Holding assets, our general and administrative services agreement was extended to December 31, 2005, and the fee increased to approximately \$1.6 million per month. In November 2002, as a result of the San Juan assets acquisition, the monthly fee under our general and administrative services agreement increased by \$1.3 million, bringing our total monthly fee to \$2.9 million. We believe this fee approximates the actual costs incurred. Under the terms of the partnership agreement, our general partner is entitled to reimbursement of all reasonable general and administrative expenses and other reasonable expenses incurred by our general partner and its affiliates for, or on our behalf, including, but not limited to, amounts payable by our general partner to El Paso Corporation under its management agreement. We are also charged for insurance and other costs paid directly by El Paso Field Services on our behalf.

As we became operator of additional facilities or systems, acquired new operations or constructed new facilities, we entered into additional management and operating agreements with El Paso Field Services. All fees paid under these contracts approximate actual costs incurred.

The following table shows the amount El Paso Field Services charged us for each of our agreements for the year ended December 31:

	2002		2001		2000	
			(In th	nousands)		
Basic management fee	\$	18,092	\$	9,300	\$	9,300
Operating fees ⁽¹⁾		38,422		19,821		10,388
Insurance and other costs		3,486		4,066		2,577
	\$	60,000	\$	33,187	\$	22,265

⁽¹⁾ Operating fees increased from 2001 to 2002 due to the acquisition of the San Juan assets and EPN Holding assets. The increase from 2000 to 2001 is due to the EPN Texas asset acquisition.

Poseidon charges were for transportation services related to transporting production from our Garden Banks Block 72 and 117 leases.

Cost Reimbursements. In connection with becoming the operator of Poseidon, we entered into an operating agreement in January 2001. For the year ended December 31, 2000, we charged Manta Ray Offshore a management fee pursuant to its management and operations agreements. All fees received under contracts approximate actual costs incurred.

As a result of becoming the operator of Deepwater Holdings' assets during 1999 and 2000, we began receiving reimbursement from Deepwater Holdings for the cost of operating HIOS, UTOS, East Breaks, Stingray, and the West Cameron dehydration facility. This reimbursement was a fixed monthly amount covering normal operating activities that was approved by each subsidiary's management committee and was based on historical operating expenses. We recorded these as a reduction to our operation and maintenance expense. To the extent our costs were more than the monthly reimbursement, our operating expenses were higher, and to the extent our costs were lower than the monthly reimbursement, our operating expense were lower. In addition, due to the timing of actual costs, we recognized fluctuations in our results of operations throughout the years.

Acquisitions

We have purchased assets from related parties. See Note 2 for a discussion of these asset acquisitions.

Other Matters

In addition to the related party transactions discussed above, pursuant to the terms of many of the purchase and sale agreements we have entered into with various entities controlled directly or indirectly by El Paso Corporation, we have been indemnified for potential future liabilities, expenses and capital requirements above a negotiated threshold. Specifically, an indirect subsidiary of El Paso Corporation has agreed to indemnify us for specific litigation matters to the extent the ultimate resolutions of these matters result in judgments against us. For a further discussion of these matters see Note 10, Commitments and Contingencies, Legal Proceedings. Some of our agreements obligate certain indirect subsidiaries of El Paso Corporation to pay for capital costs related to maintaining assets which were acquired by us, if such costs exceed negotiated thresholds. We do not believe these thresholds will be exceeded. We have made no such claims for reimbursement to date and none are contemplated to be made at this time.

We have also entered into contracts with El Paso Merchant Energy for transportation and storage. El Paso Corporation announced on November 8, 2002 its intention to exit the energy trading business which is party to these contracts. El Paso Merchant Energy North America Company could sell or transfer to third parties the natural gas transportation and storage agreements they have with us, or El Paso Merchant Energy North America Company could request a cancellation of the transportation and storage agreements. In 2002, these agreements represented revenue of approximately \$33 million. At present, El Paso Merchant Energy North America Company continues to fully utilize these agreements.

We have also entered into capital contribution arrangements with regulated pipelines owned by El Paso Corporation in the past, and will most likely do so in the future, as part of our normal commercial activities in the Gulf of Mexico. Regulated pipelines often contribute capital toward the construction costs of gathering facilities owned by others which are connected to their pipelines. We have agreements with ANR Pipeline Company and Tennessee Gas Pipeline Company under which we will receive a total of approximately \$12 million of capital toward the construction of gathering pipelines to the Marco Polo and Medusa discoveries, payable over the next eighteen months. We will account for these payments as a reduction in property, plant and equipment. As of December 31, 2002, we received approximately \$2 million from ANR Pipeline Company as contributions in aid of construction of the Marco Polo pipeline.

At December 31, 2002 and 2001, our accounts receivable due from related parties was \$83.8 million and \$23.0 million. At December 31, 2002 and 2001, our accounts payable due to related parties was \$86.1 million and \$10.1 million.

Our accounts receivable due from related parties consisted of the following as of:

December 31, December 31,

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⁽ii) The December 2002 receivable balance includes approximately \$15 million of natural gas imbalances relating to our EPN Holding acquisition.

Our accounts payable due to related parties consisted of the following as of:

December 31, December 31,

	2002	2001	
	(In thousands)		
El Paso Corporation			
El Paso Merchant Energy North America Company	\$ 8,871	\$ 7	
El Paso Production Company	14,518	_	
Tennessee Gas Pipeline Company	1,319	595	
El Paso Field Services ⁽¹⁾	55,648	8,283	
El Paso Natural Gas Company	1,475		
El Paso Corporation	4,181	560	
Other	132	291	
	86,144	9,736	
Unconsolidated Subsidiaries			
Poseidon Oil Pipeline Company	_	332	
Total	\$ 86,144	\$ 10,068	

⁽¹⁾ The December 2002 payable balance includes approximately \$19 million of working capital adjustments relating to our EPN Holding acquisition due to El Paso Field Services; and approximately \$22 million of natural gas imbalances relating to our EPN Holding acquisition.

In connection with the San Juan assets acquisition in November 2002, we acquired a 50 percent interest in Coyote Gas Treating LLC. As part of this transaction we assumed a note receivable due from our unconsolidated affiliate, Coyote, for \$17.1 million.

In connection with the sale of our Gulf of Mexico assets in January 2001, El Paso Corporation agreed to make quarterly payments to us of \$2.25 million for three years beginning March 2001 and ending with a \$2 million payment in the first quarter of 2004. The present value of the amounts due from El Paso Corporation were classified as follows:

ι	December 31	, December 31,		
	2002	2001		
	(In thousands)			
Accounts receivable, net	\$ 8,403	\$ 7,745		
Other noncurrent assets	1,960	10,362		
	\$ 10,363	\$ 18,107		

10. Commitments and Contingencies

Legal Proceedings

Grynberg. In 1997, we were named defendants in actions brought by Jack Grynberg on behalf of the U.S. Government under the False Claims Act. Generally, these complaints allege an industry-wide conspiracy to underreport the heating value as well as the volumes of the natural gas produced from federal and Native American lands, which deprived the U.S. Government of royalties. The plaintiff in this case seeks royalties that he contends the government should have received had the volume and heating value of natural gas produced from royalty properties been differently measured, analyzed, calculated and reported, together with interest, treble damages, civil penalties, expenses and future injunctive relief to require the defendants to adopt allegedly appropriate gas measurement practices. No monetary relief has been specified in this case. These matters have been consolidated for pretrial purposes (In re: Natural Gas Royalties *Qui Tam* Litigation, U.S. District Court for the District of Wyoming, filed June 1997). In May 2001, the court denied the defendants' motions to dismiss. Discovery is proceeding.

Will Price (formerly Quinque). We have also been named defendants in Quinque Operating Company, et al v. Gas Pipelines and Their Predecessors, et al, filed in 1999 in the District Court of Stevens County, Kansas. Quinque has been dropped as a plaintiff and Will Price has been added. This class action complaint alleges that the defendants mismeasured natural gas volumes and heating content of natural gas on non-federal and non-Native American lands. The plaintiff in this case seeks certification of a nationwide class of gas working interest owners and gas royalty owners to recover royalties that the plaintiff contends these owners should have received had the volume and heating value of natural gas produced from their properties been differently measured, analyzed, calculated and reported, together with prejudgment and postjudgment interest, punitive damages, treble damages, attorney's fees, costs and expenses, and future injunctive relief to require the defendants to adopt allegedly appropriate gas measurement practices. No monetary relief has been specified in this case. Plaintiffs motion for class certification has been argued and we are awaiting a ruling.

Our Argo L.L.C. subsidiary received a claim from its contractor related to the Prince TLP. The contractor received a request for additional payments from its subcontractor as a result of variation orders and was seeking to pass these costs along to Argo. After negotiations, the contractor, the subcontractor and Argo agreed upon a settlement in July 2002. This settlement did not have a material adverse effect on our financial position, results of operations or cash flow.

Under the terms of our agreement with El Paso Corporation pursuant to which we acquired the EPN Holding assets, subsidiaries of El Paso Corporation have agreed to indemnify us against all obligations related to existing legal matters at the acquisition date, including the legal matters involving Leapartners, L.P., City of Edinburg, Houston Pipe Line Company LP and City of Corpus Christi discussed below.

During 2000, Leapartners, L.P. filed a suit against El Paso Field Services and others in the District Court of Loving County, Texas, alleging a breach of contract to gather and process gas in areas of western Texas related to an asset now owned by EPN Holding. In May 2001, the court ruled in favor of Leapartners and entered a judgment against El Paso Field Services of approximately \$10 million. El Paso Field Services has filed an appeal with the Eighth Court of Appeals in El Paso, Texas. Briefs have been filed and oral arguments were heard in November 2002. Review by the Court of Appeals is expected in early 2003.

Also, EPGT Texas Pipeline L.P., now owned by EPN Holding, is involved in litigation with the City of Edinburg concerning the City's claim that EPGT Texas was required to pay pipeline franchise fees under a contract the City had with Rio Grande Valley Gas Company, which was previously owned by EPGT Texas and is now owned by Southern Union Gas Company. An adverse judgment against Southern Union and EPGT Texas was rendered in Hidalgo County State District court in December 1998 and found a breach of contract, and held both EPGT Texas and Southern Union jointly and severally liable to the City for approximately \$4.7 million. The judgment relies on the single business enterprise doctrine to impose contractual obligations on EPGT Texas and Southern Union's entities that were not parties to the contract with the City. EPGT Texas has appealed this case to the Texas Supreme Court seeking reversal of the judgment rendered against EPGT Texas. The City seeks a remand to the trial court of its claim of tortious interference against EPGT Texas. Briefs have been filed and oral arguments were held in November 2002, and we are awaiting a decision.

In December 2000, a 30-inch natural gas pipeline jointly owned by El Paso Energy Intrastate, now owned by EPN Holding, and Houston Pipe Line Company LP ruptured in Mont Belvieu, Texas, near Baytown, resulting in substantial property damage and minor physical injury. El Paso Energy Intrastate is the operator of the pipeline. In December 2000 a lawsuit was filed in the state district court in Chambers County, Texas by eight plaintiffs, including two homeowners' insurers. The suits seek recovery for physical pain and suffering, mental anguish, physical impairment, medical expenses, and property damage. Houston Pipe Line Company has been added as an additional defendant. In accordance with the terms of the operating agreement, El Paso Energy Intrastate has agreed to assume the defense of and to indemnify Houston Pipe Line Company. In September 2002, an agreement was reached to settle the claims of two plaintiffs (including one of the insurers). The discovery phase of the lawsuit is proceeding and trial is expected in early 2003.

The City of Corpus Christi, Texas ("City") is alleging that EPGT Texas and various Coastal entities owe it monies for past obligations under City ordinances that propose to tax EPGT Texas on its gross receipts from local natural gas sales for the use of street rights-of-way. No lawsuit has been filed to date. Some but not all of the EPGT Texas pipe at issue has been using the rights-of-way since the 1960's. In addition, the City demands that EPGT Texas agree to a going-forward consent agreement in order for EPGT Texas pipe and Coastal to have the right to remain in City rights-of-way.

In addition to the above matters, we and our subsidiaries and affiliates are named defendants in numerous lawsuits and governmental proceedings that arise in the ordinary course of our business.

For each of our outstanding legal matters, we evaluate the merits of the case, our exposure to the matter, possible legal or settlement strategies and the likelihood of an unfavorable outcome. If we determine that an unfavorable outcome is probable and can be estimated, we will establish the necessary accruals. As of December 31, 2002, we had no reserves for our legal matters.

While the outcome of our outstanding legal matters cannot be predicted with certainty, based on information known to date, we do not expect the ultimate resolution of these matters will have a material adverse effect on our financial

position, results of operations or cash flows. As new information becomes available or relevant developments occur, we will establish accruals as appropriate. The impact of these changes may have a material effect on our results of operations.

Environmental

Each of our operating segments is subject to extensive federal, state, and local laws and regulations governing environmental quality and pollution control. These laws and regulations are applicable to each segment and require us to remove or remedy the effect on the environment of the disposal or release of specified substances at current and former operating sites. As of December 31, 2002, we had a reserve of approximately \$21 million for remediation costs expected to be incurred over time associated with mercury meters. We assumed this liability in connection with our April 2002 acquisition of the EPN Holding assets. El Paso Corporation has agreed to indemnify us for all the known and unknown environmental liabilities related to the assets we purchased as part of the San Juan assets acquisition up to the purchase price of \$766 million. We will only be indemnified for unknown liabilities for up to three years from the purchase date. In addition, we have been indemnified by third parties for remediation costs associated with other assets we have purchased. Also, we expect to make capital expenditures for environmental matters of approximately \$10 million in the aggregate for the years 2003 through 2007, primarily to comply with clean air regulations.

While the outcome of our outstanding environmental matters cannot be predicted with certainty, based on the information known to date and our existing accruals, we do not expect the ultimate resolution of these matters will have a material adverse effect on our financial position, results of operations or cash flows. It is possible that new information or future developments could require us to reassess our potential exposure related to environmental matters. It is also possible that other developments, such as increasingly strict environmental laws and regulations and claims for damages to property, employees, other persons and the environment resulting from our current or past operations, could result in substantial costs and liabilities in the future. As new information becomes available, or relevant developments occur, we will review our accruals and make any appropriate adjustments. While there are still uncertainties relating to the ultimate costs we may incur, based upon our evaluation and experience to date, we believe our current reserves are adequate.

Rates and Regulatory Matters

Marketing Affiliate NOPR. In September 2001, the Federal Energy Regulatory Commission (FERC) issued a Notice of Proposed Rulemaking (NOPR). The NOPR proposes to apply the standards of conduct governing the relationship between interstate pipelines and marketing affiliates to all energy affiliates. Since our High Island Offshore System (HIOS) and Petal Gas Storage facility are interstate facilities as defined by the Natural Gas Act, the proposed regulations, if adopted by FERC, would dictate how HIOS and Petal conduct business and interact with all of our energy affiliates and El Paso Corporation's energy affiliates. In December 2001, we filed comments with the FERC addressing our concerns with the proposed rules. A public hearing was held in May 2002, providing an opportunity to comment further on the NOPR. Following the conference, additional comments were filed by us. At this time, we cannot predict the outcome of the NOPR, but adoption of the regulations in the form proposed would, at a minimum, place additional administrative and operational burdens on us.

If the standards of conduct NOPR is adopted by the FERC, we will be required to functionally separate our HIOS and Petal interstate facilities from our other entities. Under the proposed rule, we would be required to dedicate employees to manage and operate our interstate facilities independently from our other non-jurisdictional facilities. This employee group would be required to function independently and would be prohibited from communicating non-public transportation information to affiliates. Separate office facilities and systems would be necessary because of the requirement to restrict affiliate access to interstate transportation information. The NOPR also limits the sharing of employees and officers with non-regulated entities. Because of the loss of synergies and shared employee restrictions, a disposition of the interstate facilities may be necessary for us to effectively comply with the rule. At this time, we cannot predict the outcome of this NOPR.

Negotiated Rate NOI. In July 2002, the FERC issued a Notice of Inquiry (NOI) that seeks comments regarding its 1996 policy of permitting pipelines to enter into negotiated rate transactions. The FERC is now reviewing whether negotiated rates should be capped, whether or not the "recourse rate" (a cost of service based rate) continues to safeguard against a pipeline exercising market power, as well as other issues related to negotiated rate programs. At this time, we cannot predict the outcome of this NOI.

Cash Management NOPR. In August 2002, the FERC issued a NOPR requiring that all cash management or money pool arrangements between a FERC regulated subsidiary and a non-FERC regulated parent must be in writing, and set forth: the duties and responsibilities of cash management participants and administrators; the methods of calculating interest and for allocating interest income and expenses; and the restrictions on deposits or borrowings by money pool members. The NOPR also requires specified documentation for all deposits into, borrowings from, interest income from, and interest expenses related to, these arrangements. Finally, the NOPR proposes that as a condition of participating in a cash management or money pool arrangement, the FERC regulated entity must maintain a minimum proprietary capital balance of 30 percent, and the FERC regulated entity and its parent must maintain investment grade credit ratings. In August 2002 comments were filed. The FERC held a public conference in September 2002, to discuss the issues raised in the comments. Representatives of companies from the gas and electric industries participated on a panel and uniformly agreed that the proposed regulations should be revised substantially and that the proposed capital balance and investment grade credit rating requirements would be excessive. At this time, we cannot predict the outcome of this NOPR.

Also in August 2002, FERC's Chief Accountant issued an Accounting Release, which was effective immediately, providing guidance on how companies should account for money pool arrangements and the types of documentation that should be maintained for these arrangements. However, the Accounting Release did not address the proposed requirements that the FERC regulated entity maintain a minimum proprietary capital balance of 30 percent and that the entity and its parent have investment grade credit ratings. Requests for rehearing were filed in August 2002. The FERC has not yet acted on the rehearing requests.

If the cash management NOPR is adopted by the FERC, our HIOS and Petal interstate facilities will no longer be permitted to participate in a money pool or cash management program. As a result, more frequent distributions or equity contributions may be needed in anticipation of monthly cash flow requirements for those interstate facilities. Also, separate credit facilities and resources may be required to support the capital and day-to-day activities for the interstate facilities separate from other of our subsidiaries and our primary bank accounts.

Emergency Reconstruction of Interstate Natural Gas Facilities NOPR. In April 2002, FERC and the Department of Transportation, Office of Pipeline Safety convened a technical conference to discuss how to clarify, expedite, and streamline permitting and approvals for interstate pipeline reconstruction in the event of disaster, whether natural or otherwise. In January 2003, FERC issued a NOPR proposing to (1) expand the scope of construction activities authorized under a pipeline's blanket certificate to allow replacement of mainline facilities; (2) authorize a pipeline to commence reconstruction of the affected system without a waiting period; and (3) authorize automatic approval of construction that would be above the normal cost ceiling. Comments on the NOPR were due on February 27, 2003. At this time we cannot predict the outcome of this rulemaking.

Pipeline Safety Notice of Proposed Rulemaking. On January 28, 2003, the U.S. Department of Transportation issued a NOPR proposing to establish a rule requiring pipeline operators to develop integrity management programs to comprehensively evaluate their pipelines, and take measures to protect pipeline segments located in what the notice refers to as "high consequence areas." The proposed rule resulted from the enactment of the Pipeline Safety Improvement Act of 2002, a new bill signed into law in December 2002. We intend to submit comments on the NOPR, which are due on March 31, 2003. At this time, we cannot predict the outcome of this rulemaking.

Other Regulatory Matters. Our HIOS system is subject to the jurisdiction of the FERC in accordance with the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978. HIOS operates under a separate FERC approved tariff that governs its operations, terms and conditions of service, and rates. We timely filed a required rate case for our HIOS system on December 31, 2002. The rate filing and tariff changes are based on HIOS' cost of service, which includes operating costs, a management fee, and changes to depreciation rates and negative salvage amortization. HIOS' filing reflects zero rate base; therefore, a management fee in place of a return on rate base has been requested. We requested the rates be effective February 1, 2003, but the FERC suspended the rate increase until July 1, 2003, subject to refund. The FERC has scheduled a hearing on this matter commencing November 17, 2003.

In June 2002, Petal Gas Storage, which is also subject to the FERC's jurisdiction filed with the FERC a certificate application to add additional gas storage capacity to Petal's storage system. The filing included a new storage cavern with a working gas capacity of 5 Bcf, the conversion and enlargement of an existing subsurface brine storage cavern to a gas storage cavern with a working capacity of 3 Bcf and related surface facilities, natural gas, water and brine transmission lines. In February 2003, the FERC approved the facilities proposed by Petal.

In December 1999, EPGT Texas filed a petition with the FERC for approval of its rates for interstate transportation service. In June 2002, the FERC issued an order that required revisions to EPGT Texas' proposed maximum rates. The changes ordered by the FERC involve reductions to rate of return, depreciation rates and revisions to the proposed rate design, including a requirement to separately state rates for gathering service. FERC also ordered refunds to customers for the difference, if any, between the originally proposed levels and the revised rates ordered by the FERC. We believe the amount of any rate refund would be minimal since most transportation services are discounted from the maximum rate. EPGT Texas has established a reserve for refunds. In July 2002, EPGT Texas requested rehearing on certain issues raised by the FERC's order, including the depreciation rates and the requirement to separately state a gathering rate. EPGT Texas' request for rehearing has been granted for further consideration and is pending before the FERC.

In July 2002, Falcon Gas Storage also requested late intervention and rehearing of the order. Falcon asserts that EPGT Texas' imbalance penalties and terms of service preclude third parties from offering imbalance management services. Meanwhile in December 2002, EPGT Texas amended its Statement of Operating Conditions to provide shippers the option of resolving daily imbalances using a third-party imbalance service provider. Falcon objected to the changes, complaining that imbalance resolution is the lowest priority of service. EPGT Texas responded to Falcon's objection and untimely intervention, repeating its request that Falcon's intervention be dismissed.

In December 2002, EPGT Texas requested FERC approval of market-based rates for interstate gas storage services performed at its Wilson storage facility. The filing was in compliance with a requirement to rejustify its existing rates or request new rates by December 20, 2002. The requested market-based rates are currently subject to refund. Falcon also intervened in this filing, complaining that market-based rates should be denied because of their complaint about access on the EPGT pipeline for third party imbalance services. We filed a response stating that their complaint is not relevant to the rate case, that a severance of this issue has been requested in the EPGT pipeline rate case, and requesting a dismissal of their intervention. This matter is pending before the FERC.

While the outcome of all of our rates and regulatory matters cannot be predicted with certainty, based on information known to date, we do not expect the ultimate resolution of these matters will have a material adverse effect on our financial position, results of operations or cash flows. As new information becomes available or relevant developments occur, we will review our accruals and make any appropriate adjustments. The impact of these changes may have a material effect on our results of operations.

Operating Lease

We have long-term operating lease commitments associated with the Wilson natural gas storage facility we acquired in April 2002 in connection with the EPN Holding acquisition. The term of the natural gas storage facility and base gas leases runs through January 2008, and subject to certain conditions, has one or more optional renewal periods of five years each at fair market rent at the time of renewal.

The future minimum lease payments under these operating lease commitments as of December 31, 2002 are as follows (in thousands):

2003	\$ 5,219
2004	5,219
2005	5,219
2006	5,219
2007	5,219
Remainder	2,609
Total minimum lease payments	\$ 28,704

Rental expense under operating leases was approximately \$3.9 million for the year ended December 31, 2002. We did not have any operating leases prior to our acquisition of the EPN Holding assets.

Guarantees

We conduct our business through our wholly-owned subsidiaries, joint ventures and other ownership arrangements to construct, operate and finance the development of our onshore and offshore midstream energy businesses. Third parties routinely require us to provide performance and financial guarantees to support the obligations of our subsidiaries under contracts entered into in connection with our business. The events and circumstances that may require us, on behalf of our subsidiaries, to perform under these guarantees include nonperformance by our joint ventures and other affiliates of services, such as gathering, transportation, processing and storage services, and nonpayment of contractual obligations.

As of December 31, 2002, we had approximately \$132.8 million of performance guarantees in connection with the activities of our joint ventures and other affiliates. Such contingent obligations are not recorded in our consolidated financial statements unless they become payable. The most significant of our performance guarantee commitments is related to the construction of the Marco Polo TLP facility. We have guaranteed the payment of approximately \$51 million as of December 31, 2002, under the turnkey construction contract between Deepwater Gateway and the construction contractor. We are obligated to perform under this guarantee should Deepwater Gateway fail to satisfy its obligations by drawing under its \$155 million project finance loan or Deepwater Gateway's joint venture partners fail to perform under their joint venture agreement. Our commitment under this guarantee is scheduled to expire in 2003.

As discussed in Note 6, we are also obligated under an agreement with certain lenders to make payments on behalf of Deepwater Gateway for all distributions we or any of our subsidiaries receive up to \$22.5 million, if Deepwater Gateway defaults on its payment obligations under their project finance loan. Neither we, nor any of our subsidiaries have received any distributions from Deepwater Gateway as of December 31, 2002.

Other Matters

As a result of current circumstances generally surrounding the energy sector, the creditworthiness of several industry participants has been called into question. As a result of these general circumstances, we have established an internal group to monitor our exposure to and determine, as appropriate, whether we should request prepayments, letters of credit or other collateral from our counterparties.

11. Accounting for Hedging Activities

A majority of our commodity purchases and sales, which relate to purchases and sales of natural gas associated with our EPIA pipeline and San Juan assets, sales of liquids associated with our interest in the Indian Basin processing plant and sales of oil and natural gas associated with our production operations, are at spot market or forward market prices. We use futures, forward contracts, and swaps to limit our exposure to fluctuations in the commodity markets and allow for a fixed cash flow stream from these activities. On January 1, 2001, we adopted the provisions of SFAS No. 133, *Accounting for Derivatives and Hedging Activities*. We did not have any derivative contracts in place at December 31, 2000, and therefore, there was no transition adjustment recorded in our financial statements. During 2002 and 2001, we entered into cash flow hedges.

In August 2002, we entered into a derivative financial instrument to hedge our exposure during 2003 to changes in natural gas prices relating to gathering activities in the San Juan Basin in anticipation of our acquisition of the San Juan assets. The derivative is a financial swap on 30,000 MMBtu per day whereby we receive a fixed price of \$3.525 per MMBtu and pay a floating price based on the San Juan index. From August 2002 through our acquisition date, November 27, 2002, we accounted for this derivative under mark-to-market accounting since it did not qualify for hedge accounting under SFAS 133. Through the acquisition date, we recognized a \$0.4 million gain in the margin of our Natural gas pipelines and plants segment. Beginning with the acquisition date in November 2002, we are accounting for this derivative as a cash flow hedge under SFAS No. 133. As of December 31, 2002, the fair value of this cash flow hedge was a liability of \$4.8 million. No ineffectiveness exists in our hedging relationship because all purchase and sale prices are based on the same index and volumes as the hedge transaction. We estimate the entire amount will be reclassified from accumulated other comprehensive income to earnings over the next 12 months. In connection with our San Juan asset purchase, we also acquired the outstanding risk management positions at the Chaco plant. The value of these NGL and natural gas positions was a \$0.5 million liability at the acquisition date and this amount was included in the working capital adjustments to the purchase price. These positions expired in December 2002.

At December 31, 2002, in connection with our EPIA operations, we have fixed price contracts with specific customers for the sale of predetermined volumes of natural gas for delivery over established periods of time. We entered into cash flow hedges in 2001 and 2002 to offset the risk of increasing natural gas prices. As of December 31, 2002, the fair value of these cash flow hedges was an asset of approximately \$86 thousand. For the twelve months ended December 31, 2002, the majority of these cash flow hedges expired and we reclassified a loss of \$1.4 million from accumulated other comprehensive income to earnings. We estimate the entire amount will be reclassified from accumulated other comprehensive income to earnings over the next six months. As of December 31, 2001, the fair value of these cash flow hedges was a liability of \$1.3 million. During the year ended December 31, 2001, we reclassified a gain of \$400 thousand from other comprehensive income to earnings. No ineffectiveness exists in our hedging relationship because all purchase and sale prices are based on the same index and volumes as the hedge transaction.

Beginning in April 2002, in connection with our EPN Holding acquisition, we had swaps in place for our interest in the Indian Basin processing plant to hedge the price received for the sale of natural gas liquids. All of these hedges expired by December 31, 2002, and we recorded a loss of \$163 thousand during 2002 for these cash flow hedges. We did not have any ineffectiveness in our hedging relationship since all sale prices were based on the same index as the hedge transaction.

In January 2002, Poseidon entered into a two-year interest rate swap agreement to fix the variable LIBOR based interest rate on \$75 million of its \$150 million variable rate revolving credit facility at 3.49% over the life of the swap. Poseidon, under its credit facility, pays an additional 150 basis points over the LIBOR rate resulting in an effective interest rate at 4.99% on the hedged notional amount. As of December 31, 2002, the fair value of its interest rate swap was a liability of \$1.4 million resulting in accumulated other comprehensive loss of \$1.4 million. We included our

36 percent share of this liability of \$0.5 million as a reduction of our investment in Poseidon and as loss in accumulated other comprehensive income which will be reclassified to earnings proportionately over the next twelve months. Additionally, we have recognized in income our 36 percent share of Poseidon's realized loss of \$1.2 million for the twelve months ended December 31, 2002, or \$0.4 million, through our earnings from unconsolidated affiliates.

Our counterparties for EPIA and Indian Basin hedging activities are EI Paso Merchant Energy and EI Paso Field Services, affiliates of our general partner. We do not require collateral and do not anticipate non-performance by our counterparties. The counterparty for Poseidon's hedging activity is Credit Lyonnais. Poseidon does not require collateral and does not anticipate non-performance by the counterparty. The counterparty of our San Juan hedging activity is J. Aron and Company, a subsidiary of Goldman Sachs. We do not require collateral and do not anticipate non-performance by the counterparty.

12. Supplemental Disclosures to the Statements of Cash Flows

Cash paid for interest, net of amounts capitalized were as follows:

		Year Ended December 31,				
		2002	2001		2000	
			(In t	housands)		
Interest	 \$	73,598	\$	41,020	\$	46,768

Noncash investing and financing activities excluded from the statements of cash flows were as follows:

	Year Ended December 31,			
	2002	2001	2000	
		(In thousands)		
Acquisition of San Juan assets				
Issuance of Series C units	\$ 350,000	\$ -	\$ -	
Investment in processing agreement classified				
to property, plant and equipment	114,412	_	_	
Acquisition of EPN Holding assets				
Issuance of common units	6,000	_	_	
Acquisition of additional 50 percent interest in				
Deepwater Holdings				
Working capital acquired	_	7,494	_	
Acquisition of Crystal natural gas storage busine	esses			
Issuance of Series B preference units .	_	_	170,000	
Working capital acquired	_	_	220	
Acquisition of EPIA				
Working capital acquired	_	_	(1,673)	

13. Major Customers

The percentage of our revenue from major customers was as follows:

	Year Ended December 31,			
	2002	2001	2000	
El Paso Merchant Energy North America Company	21%	_	_	
El Paso Field Services	18%	16%	_	
Alabama Gas Corporation	_	14%	20%	
Shell Offshore	_	_	13%	
Kerr-McGee Corporation	_	_	11%	

The 2002 percentage increase in revenue from El Paso Merchant Energy North America Company and El Paso Field Services is primarily due to our EPN Holding and San Juan asset acquisitions completed in 2002. The 2001 percentage declines in revenue from some of our major customers in 2000 is primarily attributed to increased revenue from our 2001 operations as a result of acquisitions in 2001, principally the acquisition of the EPN Texas assets and Chaco.

14. Business Segment Information:

Each of our segments are business units that offer different services and products that are managed separately since each segment requires different technology and marketing strategies. We have revised and renamed our business segments to reflect changes in the composition of our operations as discussed below. As a result we have segregated our business activities into four distinct operating segments:

- · Natural gas pipelines and plants;
- · Oil and NGL logistics;
- · Natural gas storage; and
- · Platform services.

As a result of our acquisition of EPN Texas in February 2001, we began providing NGL transportation and fractionation services and have shown these activities as a separate segment called Oil and NGL logistics. This segment also includes the liquid transportation services of the Allegheny and Poseidon oil pipelines which were previously reflected in the Natural gas pipelines and plants segment and our Chaco cryogenic gas processing plant, which we acquired in October 2001.

With the July 2001 installation of the Prince TLP facility in the Prince Field, we began managing our platform operations separately from our gathering and transportation operations. Accordingly, we have shown our platforms as a separate segment called Platform services. This segment includes the East Cameron 373, Viosca Knoll 817, Garden Banks 72, and Ship Shoal 331 and 332 platforms which were previously reflected in the Natural gas pipelines and plants segment.

As a result of our agreement to sell the Prince TLP and our 9 percent overriding royalty interest in the Prince Field to El Paso Corporation in February 2002, the results of operations from these assets are reflected as discontinued operations in our statements of income for all periods presented and are not reflected in our segment results below; nor are the related assets held for sale included in segment assets. The operations of our oil and natural gas production activities are reflected in Other. Additionally, when we acquired the Chaco processing plant in October 2001 we reflected the operations of this asset in our Oil and NGL logistics segment. In light of the expectations of acquiring

Notes to Consolidated Financial Statements, continued

additional natural gas pipeline and processing assets, effective January 1, 2002, we moved the Chaco processing plant to our Natural gas pipelines and plants segment.

We have restated the prior periods, to the extent practicable, in order to conform to the current business segment presentation. The results of operations for the restated periods are not necessarily indicative of the results that would have been achieved had the revised business structure been in effect during the period.

The accounting policies of the individual segments are the same as those described in Note 1. We record intersegment revenues at rates that approximate market. Since earnings from unconsolidated affiliates can be a significant component of earnings in several of our segments, we have chosen to evaluate segment operating performance based on earnings before interest and income taxes (EBIT) instead of operating income. We define EBIT as operating income, adjusted for several items, including: earnings from unconsolidated affiliates, minority interest of consolidated subsidiaries, gains and losses on sales of assets and other miscellaneous non-operating items. Items that are not included in this measure are financing costs, including interest and debt expense, income tax benefit and discontinued operations. We believe this measurement is useful to our investors because it allows them to evaluate the effectiveness of our business and operations and our investments from an operational perspective, exclusive of the costs to finance those activities and exclusive of income taxes, neither of which are directly relevant to the efficiency of those operations. This measurement may not be comparable to measurements used by other companies and should not be used as a substitute for net income or other performance measures such as operating cash flow.

In addition to EBIT, we also measure segment performance using EBITDA, or an asset's ability to generate cash flow. We believe our presentation of EBITDA provides additional information which may be used to determine our ability to pay distributions, service our debt obligations, and grow the business. Our management uses EBITDA, in addition to other information, to evaluate the performance of our assets, determine how resources will be allocated, and develop strategic plans. These measures are used as a supplemental financial measurement in the evaluation of our business and should not be considered as an alternative to GAAP measures as indicators of our operating performance or as measures of our liquidity. EBITDA may not be a comparable measurement among different companies.

Our operating results and financial position reflect the acquisitions of the San Juan assets in November 2002, the EPN Holding assets in April 2002, the Chaco plant and the remaining 50 percent interest we did not already own in Deepwater Holdings in October 2001, EPN Texas in February 2001, the Petal and Hattiesburg natural gas storage facilities in August 2000 and EPIA in March 2000. The acquisitions were accounted for as purchases and therefore operating results of these acquired entities are included prospectively from the purchase date.

The following are results as of and for the periods ended December 31:

	Natural Gas Pipelines & Plants	NGL Logistics	Natural Gas Storage	Platform Services	Other ⁽¹⁾	Total
- " V - 1 15 1 01		((In thousand	s)		
For the Year Ended December 31,	2002					
Revenue from external	0.057504	Ó 40470	ά 00 000	Ó 40.070	Ć 10.000	0 407040
customers	\$ 357,581	\$ 48,173	\$ 28,602	\$ 16,672	\$ 16,890	\$ 467,918
Intersegment revenue	227	_	_	9,283	(9,510)	_
Depreciation, depletion and	44.470	C 404	0.500	4.005	0.450	70.100
amortization	44,479	6,481	8,503	4,205	8,458	72,126
Operating income (loss)	121,568	21,059	8,126	18,749	(8,219)	161,283
Earnings (loss) from unconsolidated investments	10.4	10 445				12.620
	194	13,445	0 106	18,863	(6,821)	13,639
EBIT EBITDA	121,371 167,245	34,507 43,347	8,126 16,629	29,224	10,427	176,046 266,872
Assets	2,279,955	265,900	320,662	140,758	123,621	3,130,896
For the Year Ended December 31,		200,900	320,002	140,730	123,021	3,130,696
Revenue from external	2001					
customers	\$ 100,683	\$ 32,327	\$ 19,373	\$ 15,385	\$ 25,638	\$ 193,406
Intersegment revenue	381	\$ 52,527	\$ 15,575	12,620	(13,001)	\$ 195,400
Depreciation, depletion and	301	_	_	12,020	(13,001)	_
amortization	12,378	5,113	5,605	4,154	7,528	34,778
Asset impairment charge	3,921	5,115	3,003	4,104	7,520	3,921
Operating income (loss)	22,349	20,235	7,584	20,754	(1,036)	69,886
Earnings (loss) from	22,040	20,200	7,004	20,704	(1,000)	00,000
unconsolidated investments	(9,761)	18,210	_	_	_	8,449
EBIT	27,413	38,445	7,604	20,122	2,010	95,594
EBITDA	52,152	47,560	13,209	30,783	17,636	161,340
Assets	563,698	195,839	226,991	115,364	69,968	1,171,860
For the Year Ended December 31,		100,000	220,001	110,004	00,000	1,17 1,000
Revenue from external						
customers	\$ 63,499	\$ 8,307	\$ 6,182	\$ 13,875	\$ 20,552	\$ 112,415
Intersegment revenue	629		- 0,.02	12,958	(13,587)	_
Depreciation, depletion and	020			.2,000	(10,001)	
amortization	8,062	1,391	1,868	4,445	11,977	27,743
Operating income (loss)	26,183	6,876	2,190	22,491	(15,689)	42,051
Earnings from unconsolidated	20,.00	0,010	_,.00	,	(.5,550)	,001
investments	10,213	12,718	_	_	_	22,931
EBIT	36,987	21,322	2,193	22,491	(15,729)	67,264
EBITDA	55,106	28,527	4,061	24,686	(5,371)	107,009
Assets	345,309	65,734	176,420	111,810	48,706	747,979
	3 .5,500	55,. 61	0, .20	,0 10	.5,. 50	,

⁽¹⁾ Represents predominately our oil and natural gas production activities as well as intersegment eliminations. Our intersegment revenues, along with our intersegment operating expenses, consist of normal course of business-type transactions between our operating segments. We record an intersegment revenue elimination, which is the only elimination included in the "Other" column, to remove intersegment transactions.

Reconciliation of EBITDA by Segment

	Pi	tural Gas pelines &		Oil and NGL		Natural Gas		Platform				
		Plants	Lo	gistics		itorage nousands		ervices	(Other ⁽¹⁾		Total
The Year Ended December 31, 200)2			(,111 (1	Tododitad	')					
Net income											\$	97,688
Plus: Interest and debt expense(1)												83,494
Less: Income from discontinued												
operations												5,136
EBIT	\$	121,371	\$	34,507	\$	8,126	\$	18,863	\$	(6,821)		176,046
Plus: Depreciation, depletion and												
amortization		44,479		6,481		8,503		4,205		8,458		72,126
Cash distributions from												
unconsolidated affiliates		2,000		15,804		_		_		_		17,804
Net cash payment received from												
El Paso Corporation		_		_		_		_		7,745		7,745
Discontinued operations of Princ	е											
facilities		_		_		_		6,156		1,045		7,201
Less: Earnings from unconsolidated												
affiliates		194		13,445		_		_		_		13,639
Noncash hedge gain	_	411	_		_		_				_	411
EBITDA ⁽²⁾	\$	167,245	\$	43,347	\$	16,629	\$	29,224	\$	10,427	\$	266,872
Year Ended December 31, 2001	_						_					
Net income											\$	55,149
Plus: Interest and debt expense(1)												41,542
Less: Income from discontinued												
operations												1,097
EBIT	\$	27,413	\$	38,445	\$	7,604	\$	20,122	\$	2,010		95,594
Plus: Depreciation, depletion and												
amortization		12,378		5,113		5,605		4,154		7,528		34,778
Asset impairment charge		3,921		_		_		_		_		3,921
Cash distributions from												
unconsolidated affiliates		12,850		22,212		_		_		_		35,062
Net cash payment received from										7.400		7.400
El Paso Corporation		_		_		_		_		7,426		7,426
Discontinued operations of Princ								5.000		070		0.504
facilities		_		_		_		5,889		672		6,561
Loss on sale of Gulf of Mexico		7700						4.050				11051
assets		7,793		_		_		4,058		_		11,851
Less: Earnings (loss) from		(0.701)		10.010								0.440
unconsolidated affiliates		(9,761)		18,210		_		_		_		8,449
Non-cash earnings related to												
future payments from El Paso		21.064						3,440				25.404
Corporation	\$	21,964 52,152	\$	47,560	\$	13,209	Ś	30,783	\$	17,636	\$	25,404 161,340
LOHOR	=	02,102	=	-1,500	=	10,200	=		=		=	

⁽i) We finance our activities at the consolidated level and therefore we do not allocate interest and debt expense among our segments.

⁽²⁾ EBITDA is determined by taking earnings before interest and income taxes and adding or subtracting, as appropriate, cash distributions from unconsolidated affiliates; depreciation, depletion and amortization; earnings from unconsolidated affiliates; gains and losses on asset sales; and other nonrecurring items.

Reconciliation of EBITDA by Segment

		tural Gas pelines &				Platform					
		Plants	L	ogistics		Storage	S	Services		Other(1)	Total
						(In thous	san	ds)			
The Year Ended December 31, 2000	0										
Net income											\$ 20,497
Plus: Interest and debt expense(1)											46,820
Less: Income from discontinued											
operations											(252)
Income tax benefit											305
EBIT	\$	36,987	\$	21,322	\$	2,193	\$	22,491	\$	(15,729)	67,264
Plus: Depreciation, depletion and											
amortization		8,062		1,391		1,868		4,445		11,977	27,743
Cash distributions from											
unconsolidated affiliates		20,428		13,532		_		_		_	33,960
Insurance proceeds		_		5,000		_		_		_	5,000
Less: Earnings from unconsolidated											
affiliates		10,213		12,718		_		_		_	22,931
Litigation resolution		_		_		_		2,250		_	2,250
Hedging activities		_		_		_		_		1,619	1,619
Gain on sale of assets		158		_		_		_		_	158
EBITDA ⁽²⁾	\$	55,106	\$	28,527	\$	4,061	\$	24,686	\$	(5,371)	\$ 107,009

⁽⁰⁾ We finance our activities at the consolidated level and therefore we do not allocate interest and debt expense among our segments.

⁽²⁾ EBITDA is determined by taking earnings before interest and income taxes and adding or subtracting, as appropriate, cash distributions from unconsolidated affiliates; depreciation, depletion and amortization; earnings from unconsolidated affiliates; gains and losses on asset sales; and other nonrecurring items.

15. Guarantor Financial Information

In May 2001, we purchased our general partner's 1.01 percent non-managing interest owned in twelve of our subsidiaries for \$8 million. As a result of this acquisition, all our subsidiaries, but not our equity investees, are wholly owned by us. As of December 31, 2002, our revolving credit facility, EPN Holding term credit facility, senior secured term loan and senior secured acquisition term loan are guaranteed by each of our subsidiaries, excluding our unrestricted subsidiaries, and are collateralized by our general and administrative services agreement, substantially all of our assets, and our general partner's one percent general partner interest. In addition, as of December 31, 2002, all of our senior subordinated notes are jointly, severably, fully and unconditionally guaranteed by us and all our subsidiaries excluding our unrestricted subsidiaries. As of December 31, 2001, our revolving credit facility was guaranteed by us and each of our subsidiaries (excluding Argo, L.L.C. and Argo I, L.L.C. subsidiaries) and was collateralized by our general and administrative services agreement, substantially all of our assets, and our general partner's one percent general partner interest. In addition, all of our senior subordinated notes were guaranteed by all of our subsidiaries except Argo and Argo I. The consolidating eliminations column on our balance sheets eliminate our investment in consolidating subsidiaries, intercompany payables and receivables and other transactions between subsidiaries.

Non-guarantor subsidiaries for the year ended December 31, 2002, consisted of Argo and Argo I for the quarter ended March 31, 2002, our EPN Holding subsidiaries for the quarters ended June 30, 2002 and September 30, 2002, and our unrestricted subsidiaries for the quarter ended December 31, 2002. Non-guarantor subsidiaries for all other periods consisted of Argo and Argo I which owned the Prince TLP. As a result of our disposal of the Prince TLP and our related overriding royalty interest in April 2002, the results of operations and net book value of these assets are reflected as discontinued operations in our statements of income and assets held for sale in our balance sheets and Argo and Argo I became guarantor subsidiaries.

Condensed Consolidating Statement of Income

	Issuer	Non-guarantor Subsidiaries ⁽¹⁾		
		(In thou	sands)	
Operating revenues				
Natural gas pipelines and plants				
Natural gas sales	\$ -	\$ 30,778	\$ 54,223	\$ 85,001
NGL sales	_	15,050	17,928	32,978
Gathering and transportation	_	71,560	122,776	194,336
Processing		5,316	39,950	45,266
		122,704	234,877	357,581
Oil and NGL logistics				
Oil sales	_	_	10,636	10,636
Oil transportation	_	_	8,364	8,364
Fractionation	_	_	26,356	26,356
NGL storage	_	_	2,817	2,817
	_		48,173	48,173
Platform services	_	_	16,672	16,672
Natural gas storage	_	2,699	25,903	28,602
Other — oil and natural gas production	_	_	16,890	16,890
	_	125,403	342,515	467,918
Operating expenses				
Cost of natural gas	_	39,280	80,067	119,347
Operations and maintenance	6,056	27,701	81,405	115,162
Depreciation, depletion and amortization .	274	10,729	61,123	72,126
	6,330	77,710	222,595	306,635
Operating income (loss)	(6,330)	47,693	119,920	161,283
Other income (loss)				
Earnings from unconsolidated affiliates	_	_	13,639	13,639
Net loss on sales of assets	_	_	(473)	(473)
Minority interest	_	60	_	60
Other income	1,471	5	61	1,537
Interest and debt income (expense)	37,696	(22,048)	(99,142)	(83,494)
Income from continuing operations	32,837	25,710	34,005	92,552
Income from discontinued operations	_	4,004	1,132	5,136
Net income	\$ 32,837	\$ 29,714	\$ 35,137	\$ 97,688

⁽¹⁾ Non-guarantor subsidiaries consisted of Argo and Argo I for the quarter ended March 31, 2002; EPN Holding subsidiaries for the quarters ended June 30, 2002 and September 30, 2002; and our unrestricted subsidiaries for the quarter ended December 31, 2002.

Condensed Consolidating Statement of Income

	Issuer	Non-guaranto Subsidiaries	r Guarantor ⁾ Subsidiaries	Consolidated Total
		(In thou	ısands)	
Operating revenues				
Natural gas pipelines and plants				
Natural gas sales	\$ -	\$ -	\$ 59,701	\$ 59,701
Gathering and transportation	_	_	33,849	33,849
Processing		·	7,133	7,133
			100,683	100,683
Oil and NGL logistics				
Oil transportation	_	_	7,082	7,082
Fractionation			25,245	25,245
			32,327	32,327
Platform services	_	_	15,385	15,385
Natural gas storage	_	_	19,373	19,373
Other — oil and natural gas production			25,638	25,638
			193,406	193,406
Operating expenses				
Cost of natural gas	_	_	51,542	51,542
Operations and maintenance	(200)	_	33,479	33,279
Depreciation, depletion and amortization.	323	_	34,455	34,778
Asset impairment charge			3,921	3,921
	123		123,397	123,520
Operating income	(123)	_	70,009	69,886
Other income				
Earnings from unconsolidated affiliates	_	_	8,449	8,449
Net loss on sales of assets	(10,941)	_	(426)	(11,367)
Minority interest	_	_	(100)	(100)
Other income	28,492	_	234	28,726
Interest and debt expense	15,328	_	(56,870)	(41,542)
Income from continuing operations	32,756		21,296	54,052
Income from discontinued operations		1,308	(211)	1,097
Net income (loss)	\$ 32,756	\$ 1,308	\$ 21,085	\$ 55,149

 $^{^{\}scriptscriptstyle{(1)}}$ Non-guarantor subsidiaries consist of Argo and Argo I, which were formed in August 2000.

Condensed Consolidating Statement of Income

	Issuer	Non-guarantor Subsidiaries ⁽¹⁾		Consolidated Total
		(In thou		iotai
Operating revenues		•	,	
Natural gas pipelines and plants				
Natural gas sales	\$ -	\$ -	\$ 34,531	\$ 34,531
Gathering and transportation	_	_	28,968	28,968
			63,499	63,499
Oil and NGL logistics				
Oil transportation	_	_	8,307	8,307
			8,307	8,307
Platform services	_	_	13,875	13,875
Natural gas storage	_	_	6,182	6,182
Other — oil and natural gas production	_	_	20,552	20,552
			112,415	112,415
Operating expenses				
Cost of natural gas	_	_	28,160	28,160
Operation and maintenance	(323)	_	14,784	14,461
Depreciation, depletion and amortization	151	_	27,592	27,743
	(172)		70,536	70,364
Operating income	172		41,879	42,051
Other income				
Earnings from unconsolidated affiliates	_	_	22,931	22,931
Minority interest	_	_	(95)	(95)
Other income	311	_	2,066	2,377
Interest and debt expense	(70)	_	(46,750)	(46,820)
Income tax benefit	_	_	305	305
Income from continuing operations	413		20,336	20,749
Loss from discontinued operations		(252)		(252)
Net income (loss)	\$ 413	\$ (252)	\$ 20,336	\$ 20,497

Non-guarantor subsidiaries consist of Argo and Argo I, which were formed in August 2000.

Condensed Consolidating Balance Sheets

December 31, 2002

	I		•	guaranto idiaries ⁽¹		Guarantor Subsidiaries		onsolidated iminations	Co	onsolidated Total
Outro at a seeds						(In thousands)				
Current assets Cash and cash equivalents	¢	20,777	7 ¢	_	\$	15,322	¢	_	\$	36,099
Accounts receivable, net	Ų	20,111	Ų		Ų	10,022	Ų		Ų	00,000
Trade				74		139,445				139,519
		700.000	-					(60E 070)		
Affiliates		709,230)	3,055		67,513		(695,972)		83,826
Affiliated note receivable		-	-	_		17,100		_		17,100
Other current assets	—	1,118			_	2,333	_	(005.070)	_	3,451
Total current assets		731,125)	3,129		241,713		(695,972)		279,995
Property, plant and equipment,										
net		6,716	5	454		2,717,768		_		2,724,938
Intangible assets		-	-	_		3,970		_		3,970
Investments in unconsolidated										
affiliates		-	-	5,197		73,654		_		78,851
Investments in consolidated										
affiliates		1,787,767	7	_		693		(1,788,460)		_
Other noncurrent assets		205,262	2 _		_	7,879		(169,999)	_	43,142
Total assets	\$	2,730,870) \$	8,780	\$	3,045,677	\$	(2,654,431)	\$	3,130,896
Current liabilities					_				_	
Accounts payable										
Trade	\$	-	- \$	302	\$	126,422	\$	_	\$	126,724
Affiliates		18,867	7	2,982		760,267		(695,972)		86,144
Accrued interest		14,22	l	_		807		_		15,028
Current maturities of senior										
secured term loan		-	-	_		5,000		_		5,000
Other current liabilities		1,645	5	5		19,545		_		21,195
Total current					_				_	
liabilities		34,733	3	3,289		912,041		(695,972)		254,091
Revolving credit facility		491,000)	_		_		_		491,000
Senior secured term loans, less										
current maturities		397,500)	_		155,000		_		552,500
Long-term debt		857,786		_		_		_		857,786
Other noncurrent liabilities		(-		_		193,725		(169,999)		23,725
Minority interest		_	_	1,942		· _		_		1,942
Partners' capital		949,852	2	3,549		1,784,911		(1,788,460)		949,852
Total liabilities and		2 . 0,002		-,,,,,,	-	.,. 5 .,6 . 1		(.,. = 5, . 5 5)	-	1.1,002
	Ś	2,730,870) \$	8,780	\$	3,045,677	\$	(2,654,431)	Ś	3.130.896
partition capital IIIIIIIIIIIIIIII	=	_,, 00,070	= =		=	0,0 10,011	=	(2,004,401)	=	

⁽¹⁾ Non-guarantor subsidiaries consisted of Argo and Argo I for the quarter ended March 31, 2002; EPN Holding subsidiaries for the quarters ended June 30, 2002 and September 30, 2002; and our unrestricted subsidiaries for the quarter ended December 31, 2002.

Condensed Consolidating Balance Sheets

December 31, 2001

			Nor	n-guarantor	(Guarantor	Co	onsolidated	Сс	nsolidated
		Issuer	Sub	osidiaries ⁽¹⁾	Sı	ubsidiaries	E	liminations		Total
					(Ir	thousands)				
Current assets										
Cash and cash equivalents	\$	7,406	\$	2,571	\$	3,107	\$	_	\$	13,084
Accounts receivable, net										
Trade		_		191		32,971		_		33,162
Affiliates		970,935		2,125		2,303		(952,350)		23,013
Other current assets		2,375		264		(2,082)				557
Total current assets		980,716		5,151		36,299		(952,350)		69,816
Property, plant and equipment,										
net		2,371		_		915,496		_		917,867
Assets held for sale, net		_		152,734		32,826		_		185,560
Investment in processing										
agreement		_		_		119,981		_		119,981
Investments in unconsolidated										
affiliates		_		_		34,442		_		34,442
Investments in consolidated										
affiliates		51,960		_		45,849		(97,809)		_
Other noncurrent assets	_	196,777		1,089		1,887	_	(169,999)		29,754
Total assets	\$	1,231,824	\$	158,974	\$	1,186,780	\$	(1,220,158)	\$	1,357,420
Current liabilities										
Accounts payable										
Trade	\$	587	\$	3,859	\$	10,541	\$	_	\$	14,987
Affiliates		2		13,563		948,853		(952,350)		10,068
Accrued interest		5,698		703		_		_		6,401
Current maturities of limited										
recourse term loan		_		19,000		_		_		19,000
Other current liabilities		(189)				4,348				4,159
Total current										
liabilities		6,098		37,125		963,742		(952,350)		54,615
Revolving credit facility		300,000		_		_		_		300,000
Limited recourse term loan, less										
current maturities		_		76,000		_		_		76,000
Long-term debt		425,000		_		_		_		425,000
Other noncurrent liabilities		_		_		171,078		(169,999)		1,079
Partners' capital		500,726		45,849		51,960	_	(97,809)		500,726
Total liabilities and										
partners' capital	\$	1,231,824	\$	158,974	\$	1,186,780	\$	(1,220,158)	\$	1,357,420
									=	

⁽¹⁾ Non-guarantor subsidiaries consist of Argo and Argo I, which were formed in August 2000.

Condensed Consolidating Statements of Cash Flow

	Issuer	Non-guarantor Guarantor Subsidiaries ⁽¹⁾ Subsidiaries		Consolidated Total		
		(In thou		Total		
Cash flows from operating activities		,	,			
Net Income	\$ 32,837	\$ 29,714	\$ 35,137	\$ 97,688		
Less income from discontinued operations		4,004	1,132	5,136		
Income from continuing operations	32,837	25,710	34,005	92,552		
Adjustments to reconcile net income to net cash						
provided by operating activities						
Depreciation, depletion and amortization	274	10,730	61,122	72,126		
Distributed earnings of unconsolidated affiliates						
Earnings from unconsolidated affiliates	_	_	(13,639)	(13,639)		
Distributions from unconsolidated affiliates	_	_	17,804	17,804		
Net loss on sale of assets	_		473	473		
Other noncash items	4,504	(3,240)	2,992	4,256		
Working capital changes, net of acquisitions and	10.010	(45.030)	(0.750)	(0.040)		
non-cash transactions	16,810	(15,873)	(3,753)	(2,816)		
Net cash provided by continuing operations	54,425	17,327	99,004	170,756		
Net cash provided by discontinued operations		4,631	613	5,244		
Net cash provided by operating activities	54,425	21,958	99,617	176,000		
Cash flows from investing activities						
Development expenditures for oil and natural gas properties			(1,682)	(1,682)		
Additions to property, plant and equipment	(4,619)	(9,099)	(188,823)	(202,541)		
Proceeds from sale of assets	(4,019)	(9,099)	5,460	5,460		
Additions to investments in unconsolidated			3,400	3,400		
affiliates	_	(1,910)	(36,365)	(38,275)		
Cash paid for acquisitions, net of cash acquired	_	(729,000)	(435,856)	(1,164,856)		
Net cash used in investing activities of continuing						
operations	(4,619)	(740,009)	(657,266)	(1,401,894)		
Net cash provided by (used in) investing activities	()/	(2,222,	(,,	() = ,== ,		
of discontinued operations	_	(3,523)	190,000	186,477		
Net cash used in investing activities	(4,619)	(743,532)	(467,266)	(1,215,417)		
Cash flows from financing activities						
Net proceeds from revolving credit facility	359,219	7,000	_	366,219		
Repayments of revolving credit facility	(170,000)	(7,000)	_	(177,000)		
Net proceeds from EPN Holding term credit						
facility	_	530,529	(393)	530,136		
EPN Holding term credit facility repayments	_	(375,000)	_	(375,000)		
Net proceeds from senior secured acquisition term						
loan	233,236	_	_	233,236		
Net proceeds from senior secured term loan	156,530	_	_	156,530		
Net proceeds from issuance of long-term debt	423,528	_	.	423,528		
Argo term loan repayment	_	_	(95,000)	(95,000)		
Net proceeds from issuance of common units	150,159	_		150,159		
Advances with affiliates	(1,038,734)	581,601	457,133	-		
Contributions from general partner	4,095	_	_	4,095		
Distributions to partners	(154,468)			(154,468)		
Net cash provided by (used in) financing activities of continuing operations	(26.425)	727120	261740	1060 425		
Net cash used in financing activities of	(36,435)	737,130	361,740	1,062,435		
discontinued operations	_	(3)	_	(3)		
Net cash provided by (used in) financing						
activities	(36,435)	737,127	361,740	1,062,432		
Increase (decrease) in cash and cash equivalents	\$ 13,371	\$ 15,553	\$ (5,909)	23,015		
Cash and cash equivalents	= .0,077			20,010		
Beginning of period				13,084		
End of period				\$ 36,099		
·						

⁽¹⁾ Non-guarantor subsidiaries consisted of Argo and Argo I for the quarter ended March 31, 2002; EPN Holding subsidiaries for the quarters ended June 30, 2002 and September 30, 2002; and our unrestricted subsidiaries for the quarter ended December 31, 2002.

Condensed Consolidated Statements of Cash Flow

	Issuer	Non-guarantor Guarantor Subsidiaries Subsidiaries		Consolidated Total	
		(In thou	usands)		
Cash flows from operating activities					
Net Income	\$ 2,756	\$ 1,308	\$ 21,085	\$ 55,149	
Less income from discontinued operations		1,308	(211)	1,097	
Income from continuing operations	32,756	_	21,296	54,052	
Adjustments to reconcile net income to net cash					
provided by operating activities					
Depreciation, depletion and amortization	323	_	34,455	34,778	
Asset impairment charge	_	_	3,921	3,921	
Distributed earnings of unconsolidated affiliates					
Earnings from unconsolidated affiliates	_	_	(8,449)	(8,449)	
Distributions from unconsolidated affiliates	_	_	35,062	35,062	
Net loss on sales of assets	10,941	_	426	11,367	
Other noncash items	3,155	318	835	4,308	
Working capital changes, net of effects of					
acquisitions and non-cash transactions	(9,740)	385	(43,268)	(52,623)	
Net cash provided by continuing operations	37,435	703	44,278	82,416	
Net cash provided by discontinued operations	_	4,296	672	4,968	
Net cash provided by operating activities	37.435	4,999	44,950	87,384	
Cash flows from investing activities					
Development expenditures for oil and natural gas					
properties	_	_	(2,018)	(2,018)	
Additions to pipelines, platforms and facilities	(896)	_	(507,451)	(508,347)	
Proceeds from sale of assets	89,162	_	19,964	109,126	
Investments in unconsolidated affiliates	-	_	(1,487)	(1,487)	
Cash paid for acquisitions, net of cash acquired	_	_	(28,414)	(28,414)	
Net cash provided by (used in) investing activities of			(20,111)	(20,111)	
continuing operations	88,266	_	(519,406)	(431,140)	
Net cash used in investing activities of discontinued	00,200		(313,400)	(401,140)	
operations		(67267)	(1102)	(69.560)	
Net cash provided by (used in) investing		(67,367)	(1,193)	(68,560)	
activities	88,266	(67267)	(520 500)	(400 700)	
		(67,367)	(520,599)	(499,700)	
Cash flows from financing activities Net proceeds from revolving credit facility	EE0.004			EEO 004	
	559,994	_	_	559,994	
Repayments of revolving credit facility	(581,000)	_	_	(581,000)	
Net proceeds from issuance of long-term debt	243,032	-	470.040	243,032	
Advances with affiliates	(492,805)	13,563	479,242	-	
Net proceeds from issuance of common units	286,699	_	_	286,699	
Redemption of Series B preference units	(50,000)	_	_	(50,000)	
Contributions from general partner	2,843	_		2,843	
Distributions to partners	(105,923)		(486)	(106,409)	
Net cash provided by (used in) financing activities of	(107100)	40.500	4=0==0	055.450	
continuing operations	(137,160)	13,563	478,756	355,159	
Net cash provided by financing activities of					
discontinued operations		49,960		49,960	
Net cash provided by (used in) financing					
activities	(137,160)		478,756	405,119	
Net (decrease) increase in cash and cash equivalents	\$ (11,459)	\$ 1,155	\$ 3,107	(7,197)	
Cash and cash equivalents at beginning of year				20,281	
Cash and cash equivalents at end of year				\$ 13,084	

 $^{\,^{\}scriptscriptstyle{(1)}}\,\,$ Non-guarantor subsidiaries consist of Argo and Argo I, which were formed in August 2000.

Condensed Consolidated Statements of Cash Flow

		Issuer		-guarantor osidiaries ⁽¹⁾	Guaranto Subsidiar		Cor	nsolidated Total
				(In thou	ısands)			
Cash flows from operating activities								
Net Income (loss)	\$	413	\$	(252)	\$ 20,3	36	\$	20,497
Less income (loss) from discontinued operations				(252)		_		(252)
Income from continuing operations		413		_	20,3	36		20,749
Adjustments to reconcile net income to net cash								
provided by operating activities								
Depreciation, depletion and amortization		151		_	27,5	92		27,743
Distributed earnings of unconsolidated affiliates								
Earnings from unconsolidated affiliates		_		_	(22,9	31)		(22,931)
Distributions from unconsolidated								
affiliates		_		_	33,9			33,960
Other noncash items		714		_	(7	27)		(13)
Working capital changes, net of effects of								
acquisitions and non-cash transactions		(285)		800	(11,3	61)		(10,846)
Net cash provided by continuing operations		993		800	46,8	69		48,662
Net cash used in discontinued operations				(252)		_		(252)
Net cash provided by operating activities		993		548	46,8	69		48,410
Cash flows from investing activities								
Development expenditures for oil and natural gas								
properties		_		_	(1	72)		(172)
Additions to pipelines, platforms and								
facilities		(1,811)		_	(38)		(1,849)
Investments in unconsolidated affiliates		_		_	(8,9	79)		(8,979)
Cash paid for acquisitions, net of cash								
acquired		_		_	(26,4	76)		(26,476)
Other		(402)		_		21		(381)
Net cash used in investing activities of							-	
continuing operations		(2,213)		_	(35,6	44)		(37,857)
Net cash used in investing activities of								
discontinued operations		_		(88,356)		_		(88,356)
Net cash used in investing activities		(2,213)		(88,356)	(35,6	44)		(126,213)
Cash flows from financing activities								
Net proceeds from revolving credit facility		152,043		_		_		152,043
Repayments of revolving credit facility		(125,000)		_		_		(125,000)
Net proceeds from issuance of common units		100,634		_		_		100,634
Advances with affiliates		(34,765)		45,670	(10,9	05)		_
Redemption of publicly held preference units		(804)		_		_		(804)
Contributions from general partner		2,785		_		_		2,785
Distributions to partners		(78,529)		_	(8	01)		(79,330)
Net cash provided by (used in) financing	_			-				
activities of continuing operations		16,364		45,670	(11,7	06)		50,328
Net cash provided by financing activities of								
discontinued operations		_		43,554		_		43,554
Net cash provided by (used in) financing			-	<u> </u>		_		
activities		16,364		89,224	(11,7	06)		93,882
Net increase in cash and cash equivalents	\$	15,144	\$	1,416		81)		16,079
Cash and cash equivalents at beginning of year	_		_			_		4,202
Cash and cash equivalents at end of year							\$	20,281
,							_	

16. Supplemental Oil and Natural Gas Information (Unaudited):

General

This footnote discusses our oil and natural gas production activities for the years 2001 and 2000. The year 2002 is not presented since these operations are not a significant part of our business as defined by SFAS No. 69, *Disclosures About Oil and Gas Producing Activities*, and we do not expect it to become significant in the future.

Oil and Natural Gas Reserves

The following table represents our net interest in estimated quantities of proved developed and proved undeveloped reserves of crude oil, condensate and natural gas and changes in such quantities at year end 2001 and 2000. Estimates of our reserves at December 31, 2001 and 2000, have been made by the independent engineering consulting firm, Netherland, Sewell & Associates, Inc. except for the Prince Field for 2001, which was prepared by El Paso Production Company, our affiliate and operator of the Prince Field. Net proved reserves are the estimated quantities of crude oil and natural 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. Our policy is to recognize proved reserves only when economic producibility is supported by actual production. As a result, no proved reserves were booked with respect to any of our producing fields in the absence of actual production. Proved developed reserves are proved reserve volumes that can be expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped reserves are proved reserve volumes that are expected to be recovered from new wells on undrilled acreage or from existing wells where a significant expenditure is required for recompletion. Reference Rules 4-10(a)(2)(i), (iii), (iii), (3) and (4) of Regulation S-X, for detailed definitions of proved reserves, which can be found at the SEC's website, http://www.sec.gov/divisions/corpfin/forms/regsx.htm#gas.

Estimates of reserve quantities are based on sound geological and engineering principles, but, by their very nature, are still estimates that are subject to substantial upward or downward revision as additional information regarding producing fields and technology becomes available.

	Oil/Condensate	Natural Gas
	MBbls ⁽¹⁾	MMcf ⁽¹⁾
Proved reserves — December 31, 1999	1,473	17,514
Revision of previous estimates	23	1,171
Production	(295)	(7,185)
Proved reserves — December 31, 2000	1,201	11,500
Revision of previous estimates	1,852	5,913
Production ⁽²⁾	(345)	(4,172)
Proved reserves — December 31, 2001	2,708	13,241
Proved developed reserves		
December 31, 2000	1,201	9,126
December 31, 2001 ⁽²⁾	2,350	10,384

⁽¹⁾ Includes our overriding royalty interest in proved reserves on Garden Banks Block 73 and the Prince Field.

⁽²⁾ Includes our overriding royalty interest in proved reserves of 1,341 MBbls of oil and 1,659 MMcf of natural gas on our Prince Field, which began production in 2001. These reserves were not included in proved reserves prior to 2001 because, consistent with our policy, economic producibility had not been supported by actual production. Also, we had increases in estimated proved reserves relating to our producing properties, primarily at our West Delta 35 field. Actual production in the Prince Field for 2001 was 37 MBbls of oil and 32 MMcf of natural gas.

The following are estimates of our total proved developed and proved undeveloped reserves of oil and natural gas by producing property as of December 31, 2001.

	Oil (b	arrels)	Natural (Gas (Mcf)			
	Proved	Proved	Proved	Proved			
	Developed	Undeveloped	Developed	Undeveloped			
		(In the	(In thousands)				
Garden Banks Block 72	277	_	1,900	_			
Garden Banks Block 117	1,065	_	1,556	_			
Viosca Knoll Block 817	12	_	2,216	2,437			
West Delta Block 35	13	_	3,473	_			
Prince Field	983	358	1,239	420			
Total	2,350	358	10,384	2,857			

In general, estimates of economically recoverable oil and natural gas reserves and of the future net revenue therefrom are based upon a number of variable factors and assumptions, such as historical production from the subject properties, the assumed effects of regulation by governmental agencies and assumptions concerning future oil and natural gas prices, future operating costs and future plugging and abandonment costs, all of which may vary considerably from actual results. All such estimates are to some degree speculative, and classifications of reserves are only attempts to define the degree of speculation involved. For these reasons, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties, classifications of such reserves based on risk of recovery and estimates of the future net revenue expected therefrom, prepared by different engineers or by the same engineers at different times, may vary substantially. The meaningfulness of such estimates is highly dependent upon the assumptions upon which they are based.

Estimates with respect to proved undeveloped reserves that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves rather than upon actual production history. Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history will result in variations, which may be substantial, in the estimated reserves. A significant portion of our reserves is based upon volumetric calculations.

Future Net Cash Flows

The standardized measure of discounted future net cash flows relating to our proved oil and natural gas reserves is calculated and presented in accordance with SFAS No. 69. Accordingly, future cash inflows were determined by applying year-end oil and natural gas prices, as adjusted for fixed price contracts in effect, to our estimated share of future production from proved oil and natural gas reserves. The average prices utilized in the calculation of the standardized measure of discounted future net cash flows at December 31, 2001, were \$16.75 per barrel of oil and \$2.62 per Mcf of natural gas. Actual future prices and costs may be materially higher or lower. Future production and development costs were computed by applying year-end costs to future years. As we are not a taxable entity, no future income taxes were provided. A prescribed 10 percent discount factor was applied to the future net cash flows.

In our opinion, this standardized measure is not a representative measure of fair market value, and the standardized measure presented for our proved oil and natural gas reserves is not representative of the reserve value. The standardized measure is intended only to assist financial statement users in making comparisons between companies. In the table following, the amounts of future production costs have been restated to include platform access fees paid to our platform segment. See note 2 to the table for further discussion of the impact of such fees on our consolidated standardized measure of discounted future net cash flows.

	December 31,				
		2001		2000	
	(In thousands)				
Future cash inflows ⁽¹⁾	\$	80,603	\$	136,658	
Future production costs ⁽²⁾		(19,252)		(28,933)	
Future development costs		(10,530)		(11,531)	
Future net cash flows	_	50,821	_	96,194	
Annual discount at 10% rate		(11,761)		(18,488)	
Standardized measure of discounted future net cash flows	\$	39,060	\$	77,706	

Our future cash inflows include estimated future receipts from our overriding royalty interest in our Prince Field and Garden Banks Block 73. Since these are overriding royalty interests, we do not participate in the production or development costs for these fields, but do include their proved reserves, production volumes and future cash inflows in our data.

Estimated future net cash flows for proved developed and proved undeveloped reserves as of December 31, 2001, are as follows:

	P	Proved		Proved				
	De	Developed		Undevelope		Indeveloped		Total
			(In thousands)		s)			
Undiscounted estimated future net cash flows from								
proved reserves before income taxes	\$	40,518	\$	10,303	\$	50,821		
Present value of estimated future net cash flows from	_				=			
proved reserves before income taxes, discounted								
at 10%	\$	31,003	\$	8,057	\$	39,060		
					=			

Our future production costs include platform access fees paid by our oil and natural gas production business to affiliated entities included in our platforms segment. Such platform access fees are eliminated in our consolidated financial statements. The future platform access fees paid to our platform segment were \$4,960 for 2001 and \$13,080 for 2000. On a consolidated basis, our standardized measure of discounted future net cash flows was \$43,789 for 2001 and \$89,749 for 2000.

The following are the principal sources of change in the standardized measure:

	2001		2000	
	(In thousands)			
Beginning of year	\$ 77,706	\$	17,829	
Sales and transfers of oil and natural gas produced, net				
of production costs	(34,834)		(33,203)	
Net changes in prices and production costs	(55,657)		119,457	
Extensions, discoveries and improved recovery, less				
related costs	_		_	
Oil and natural gas development costs incurred during the				
year	2,018		172	
Changes in estimated future development costs	535		(511)	
Revisions of previous quantity estimates	38,090		7,846	
Accretion of discount	7,771		1,783	
Changes in production rates, timing and other	3,431		(35,667)	
End of year	\$ 39,060	\$	77,706	

Development, Exploration, and Acquisition Expenditures

The following table details certain information regarding costs incurred in our development, exploration, and acquisition activities during the years ended December 31:

	2001	2	000
	(In thou	sands)	
Development costs	\$ 2,018	\$	172
Capitalized interest	_		_
Total capital expenditures	\$ 2,018	\$	172

In each of the years presented, we elected not to incur any costs to develop our proved undeveloped reserves. However, we expect to incur approximately \$2.6 million within the next three years to develop these reserves.

Capitalized Costs

Capitalized costs relating to our natural gas and oil producing activities and related accumulated depreciation, depletion and amortization were as follows as of December 31:

	2001		
	(In t	housands)	
Oil and natural gas properties			
Proved properties	\$	54,609	
Wells, equipment, and related facilities	_	104,766	
		159,375	
Less accumulated depreciation, depletion and amortization	_	108,307	
	\$_	51,068	

Results of Operations

Results of operations from producing activities by fiscal year were as follows at December 31:

	2001		2000	
	(In thousands)			
Natural gas sales	\$ 18,248	\$	12,819	
Oil, condensate, and liquid sales	8,062	_	7,733	
Total operating revenues	26,310		20,552	
Production costs ⁽¹⁾	16,367		16,228	
Depreciation, depletion and amortization	7,567		11,280	
Results of operations from producing activities	\$ 2,376	\$	(6,956)	

⁽¹⁾ These production costs include platform access fees paid to affiliated entities included in our platform segment. Such platform access fees, which were approximately \$10 million in each of the years presented, are eliminated in our consolidated financial statements.

17. Supplemental Quarterly Financial Information:

Quarter Ended (Unaudited)										
	M	arch 31	J	une 30	Sep	tember 30	De	cember 31		Year
				(In thousands, exept per unit data)						
2002										
Operating revenues	\$	61,544	\$	120,489	\$	122,249	\$	163,636	\$	467,918
Operating income		22,397		45,777		42,370		50,739		161,283
Income from continuing operations		14,741		28,685		23,346		25,780		92,552
Income from discontinued operations		4,385		60		456		235		5,136
Net income		19,126		28,745		23,802		26,015		97,688
Income allocation										
General Partner										
Continuing operations	\$	8,691	\$	10,799	\$	10,755	\$	11,837	\$	42,082
Discontinued operations		44				5		2	_	51
	\$	8,735	\$	10,799	\$	10,760	\$	11,839	\$	42,133
Series B preference unitholders	\$	3,552	\$	3,630	\$	3,693	\$	3,813	\$	14,688
Series C unitholders	\$		\$		\$		\$	1,507	\$	1,507
Common unitholders										
Continuing operations	\$	2,498	\$	14,256	\$	8,898	\$	8,623	\$	34,275
Discontinued operations		4,341		60		451		233		5,085
	\$	6,839	\$	14,316	\$	9,349	\$	8,856	\$	39,360
Basic and diluted earnings per common unit										
Income from continuing operations	\$	0.06	\$	0.33	\$	0.20	\$	0.21	\$	0.80
Discontinued operations		0.11		_		0.01		_		0.12
	\$	0.17	\$	0.33	\$	0.21	\$	0.21	\$	0.92
Distributions declared per common unit	\$	0.625	\$	0.650	\$	0.650	\$	0.675	\$	2.600
Weighted average number of										
common units outstanding		39,941		42,842		44,130		44,069		42,814
2001										
Operating revenues	\$	54,502	\$	44,987	\$	41,268	\$	52,649	\$	193,406
Operating income		13,792		16,457		17,362		22,275		69,886
Income from continuing operations		13,716		11,572		11,558		17,206		54,052
Income (loss) from discontinued										
operations		(743)		272		479		1,089		1,097
Net income		12,973		11,844		12,037		18,295		55,149
Income (loss) allocation										
General Partner		. 700						0.00=		0.4.050
Continuing operations	\$	4,702	\$	5,902	\$	5,809	\$	8,237	\$	24,650
Discontinued operations		(7)		2		5		11		11
Conice Department of the labor	\$	4,695	\$	5,904	\$	5,814	\$	8,248	\$	24,661
Series B preference unitholders	\$	4,322	\$	4,464	\$	4,538	\$	3,904	\$	17,228
Common unitholders	Ċ	4.000	ć	1.005	Ċ	1011	Ċ	5,066	Ċ	10174
Continuing operations	\$	4,692	\$	1,205	\$	1,211	\$,	\$	12,174
Discontinued operations	<u> </u>	(736)	<u> </u>	271	<u> </u>	474	<u> </u>	1,077	<u>-</u>	1,086
Design and diluted assertings now as many	\$	3,956	\$	1,476	\$	1,685	\$	6,143	\$	13,260
Basic and diluted earnings per common unit										
Income from continuing operations	\$	0.14	\$	0.03	\$	0.04	\$	0.14	\$	0.35
Discontinued operations		(0.02)		0.01		0.01		0.03		0.03
	\$	0.12	\$	0.04	\$	0.05	\$	0.17	\$	0.38
Distributions declared per common unit	\$	0.55	\$	0.58	\$	0.58	\$	0.61	\$	2.32
Weighted average number of common units outstanding		32,471		34,070		32,471		36,209		34,376
outotallalling		02,411		04,070		02,411	_	00,200	_	07,070

e are pleased to introduce our new name—GulfTerra Energy Partners, L.F

We've chosen a name that captures the breadth and depth of our operations, both offshore and onshore. From pipelines and platforms located in the waters of the Gulf of Mexico to thousands of miles of gathering and transportation lines in the Southwest, our asset base spans the midstream.

The Gulf portion of our new name represents our origins 10 years ago offshore in the Gulf of Mexico—the extensive infrastructure base we've built over the past decade to meet the needs of Gulf producers and the near limitless potential remaining for growth in the critically important Deepwater Trend of the Gulf of Mexico.

The Terra portion of our name reflects our diverse onshore midstream asset base including pipelines, processing and treating plants, and storage facilities. Terra also represents the rock-solid strategy that has delivered years of outstanding results for our unitholders.

Behind the GulfTerra name are the assets, people, and opportunities that make us unique in the midstream.

Start with our assets. At year-end 2002, GulfTerra was the third largest master limited partnership by total assets. We are the largest transporter of natural gas, based on miles of pipeline, in the state of Texas. GulfTerra is the largest gatherer and processor of conventional natural gas in the San Juan Basin, a leading midstream service provider in the Deepwater Trend of the Gulf of Mexico, a major supplier of feed stock to the Gulf Coast refinery and petrochemical markets, and a significant salt dome storage operator in the growing gas markets of the southeastern United States.

Then there are the people of GulfTerra. You'll find skilled professionals across our system, consistently delivering value for our unitholders. You'll find them at our Houston headquarters, offshore on our platforms, and onshore along our gathering systems. Disciplined. Focused on success. Working together, our people make up the strongest midstream team in the business.

Finally, opportunities. As we launch the GulfTerra name, our financial strength, geographic diversity, and midstream service portfolio will allow us to capitalize on the most robust growth opportunities in our history. Opportunities to broaden our customer base in growing markets for oil, natural gas, and natural gas liquids. And opportunities for internal growth from more than \$1 billion of greenfield and expansion projects currently under way.

GulfTerra Energy Partners. It's more than a new name. It also marks the beginning of a new chapter for the Partnership. A chapter about opportunities as wide open as the waters of the Gulf and about financial and operational performance as solid as the ground beneath our feet.

We're pleased to introduce GulfTerra Energy Partners, delivering superior performance across the midstream.

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Investor Information

Principal Corporate Office

GulfTerra Energy Partners, L.P. 4 Greenway Plaza Houston, Texas 77046 (832) 676-6152

Transfer Agent and Registrar

Unitholder inquiries regarding distribution checks should be submitted to:
ChaseMellon Shareholder Services, L.L.C.
85 Challenger Road
Overpeck Centre
Ridgefield Park, NJ 07660
(800) 635-9270
Web site: http://www.chasemellon.com

Email: shrrelations@chasemellon.com

K-1 Tax Information

Unitholder K-1 forms are usually available from our Web site during the first week in March and mailed by the second week in March.
K-1 inquiries should be directed to:
GulfTerra Energy Partners, L.P.
P. O. Box 480927
Denver, Colorado 80248
(877) 656-6922
(800) 593-8076
www.gulfterra.com/investors.html

Stock Exchange Listing

New York Stock Exchange Symbol: GTM

For Additional Information

Additional information on GulfTerra Energy Partners, including our filings with the Securities and Exchange Commission, can be obtained without charge from our Web site at www.gulfterra.com or by writing to the Investor Relations department as shown below. Telephone inquiries should be directed to Sandy Ryan at (832) 676-5371 or Diane Bandiga at (832) 676-5302.

Investor Relations Department

GulfTerra Energy Partners, L.P. 4 Greenway Plaza, 6th Floor Houston, Texas 77046 (832) 676-3610

Visit our Web site at www.gulfterra.com

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- · Our Code of Business Conduct
- · The GulfTerra Energy Partners' Governance Guidelines
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Important Reminder To Unitholders

In recent months our units have experienced price volatility resulting from speculative trading including large short sales that we believe are being transacted by institutional hedge funds. At March 15, 2003, the short interest in our Partnership amounted to 1.3 million units – equal to 13 days of average trading volumes.

In executing these short sales brokerage firms loan to the short seller units held in their clients' accounts. Your units may be loaned out of your account without your knowledge. In addition to the potential negative price impact these short sales have on your investment, unitholders whose units are loaned out of their accounts are subject to tax-related risks as described in the following excerpt from the Partnership's prospectus.

A limited partner whose units are loaned to a short seller to cover a short sale of units may be considered as having sold those securities and would recognize a gain or loss from the disposition. During the loan period, any partnership income, gain, deduction or loss would not be reportable by the limited partner, any cash distributions received by the limited partner would be fully taxable and all of such distributions would appear to be treated as ordinary income. The IRS has announced that it is actively studying issues relating to the tax treatment of short sales of partnership interests.

We encourage our unitholders to call their brokerage account representatives to ensure that their units are not loaned out of their accounts.

Cautionary Statement Regarding Forward-Looking Statements

This report includes forward-looking statements and projections, made in reliance on the safe harbor provisions of the Private Securities Litigation Reform Act of 1995. GulfTerra Energy Partners has made every reasonable effort to ensure that the information and assumptions on which these statements and projections are based are current, reasonable, and complete. However, a variety of factors could cause actual results to differ materially from the projections, anticipated results, or other expectations expressed in this report, including, without limitation, oil and natural gas prices; continued drilling, exploration, and production activity in the areas served by GulfTerra Energy Partners; and successful negotiation of customer contracts for its pipelines, platforms, plants, and storage facilities. While the Partnership makes these statements and projections in good faith, neither the Partnership nor its management can guarantee that the anticipated future results will be achieved. Reference should be made to GulfTerra Energy Partners' (and its affiliates') and El Paso Corporation's Securities and Exchange Commission filings for additional important factors that may affect actual results.