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

Form 10-K

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

For the fiscal year ended December 31, 2007

OR

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

For the transition period from to

Commission file number: 001-32329

Copano Energy, L.L.C.
(Exact name of registrant as specified in its charter)

Delaware	**51-0411678**
(State of organization)	*(I.R.S. Employer Identification No.)*
2727 Allen Parkway, Suite 1200 **Houston, Texas**	**77019**
(Address of principal executive offices)	*(Zip Code)*

(713) 621-9547
(Registrant's telephone number, including area code)

None
(Former name, former address and former fiscal year, if changed since last report)

SECURITIES REGISTERED PURSUANT TO SECTION 12(b) OF THE ACT:

Title of Each Class	Name of Exchange on which Registered
Common Units Representing Limited Liability Company Interests	The NASDAQ Stock Market LLC

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

Title of Class
None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☑ No ☐

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

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

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ☑ Accelerated filer ☐ Non-accelerated filer ☐ (Do not check if a smaller reporting company) Smaller reporting company ☐

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

As of June 30, 2007, the aggregate market value of our voting and non-voting common equity held by non-affiliates of the registrant was approximately $1.598 billion based on $42.67 per common unit, the closing price of our common units as reported on The NASDAQ Stock Market LLC on June 29, 2007.

As of February 15, 2008, 47,378,159 of our common units were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE:

Document	Parts Into Which Incorporated
Portions of the Proxy Statement for the Annual Meeting of Unitholders of Copano Energy, L.L.C. to be held May 15, 2008	Part III

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PART I

Unless the context requires otherwise, references to "Copano," "we," "our," "us" or like terms refer to Copano Energy, L.L.C. and its wholly owned subsidiaries.

As used generally in the energy industry and in this Annual Report, the following terms have the meanings indicated below. Please read the subsection of Item 1 captioned "— Industry Overview" for a discussion of the midstream natural gas industry.

/d:	*Per day*
$/gal:	*U.S. dollars per gallon*
Bbls:	*Barrels*
Bcf:	*One billion cubic feet*
Btu:	*British thermal units*
MMBtu:	*One million British thermal units*
Mcf:	*One thousand cubic feet*
NGLs:	*Natural gas liquids, which consist primarily of ethane, propane, isobutane, normal butane, natural gasoline and stabilized condensate*
residue gas:	*The pipeline quality natural gas remaining after natural gas is processed*
Tcf:	*One trillion cubic feet*
throughput:	*The volume of product transported or passing through a pipeline, plant, terminal or other facility*

Item 1. *Business*

The following discussion of our business segments provides information regarding our principal natural gas processing plants, pipelines and other assets. For a discussion of our results of operations, including throughput and processing rates, please read Item 7 of this report, captioned "Management's Discussion and Analysis of Financial Condition and Results of Operation."

General

We are a growth-oriented midstream energy company engaged in the business of providing comprehensive services to natural gas producers, including natural gas gathering, compression, dehydration, treating, transportation, processing and conditioning. Our assets are primarily located in Oklahoma, Texas, and Wyoming and include approximately 6,000 miles of active natural gas gathering and transmission pipelines and six natural gas processing plants, with over one billion cubic feet per day, or Bcf/d, of combined processing capacity. In addition to our natural gas pipelines, we operate 150 miles of NGL pipelines and a 67-mile crude oil pipeline. We own some of our assets through our interests in entities partially owned by third parties, including approximately 600 miles of natural gas pipelines and the Southern Dome plant.

We were formed in August 2001 as a Delaware limited liability company to acquire entities operating under the Copano name since 1992. We completed our initial public offering, or IPO, on November 15, 2004. From our inception in 1992, we have grown through a combination of more than 40 acquisitions and organic growth projects, including approximately $1.3 billion in acquisitions completed since our IPO. Our common units are listed on The NASDAQ Stock Market LLC under the symbol "CPNO."

Recent Developments

Declaration of Distribution. On January 16, 2008, our Board of Directors declared a cash distribution for the three months ended December 31, 2007 of $0.51 per unit for all outstanding common units. The distribution, totaling $24.2 million, was paid on February 14, 2008 to holders of record at the close of business on February 1, 2008.

Hedge Activity. In January 2008, we purchased puts for ethane, propane, iso-butane, normal butane and West Texas Intermediate crude oil at strike prices reflecting current market conditions, and divested previously acquired put options on these products at lower strike prices. These transactions were conducted through two investment grade counterparties in accordance with our risk management policy and were designated as cash flow hedges to mitigate the impact of decreases in NGL prices. Our net costs for these transactions were approximately $15.6 million.

For a more detailed discussion of our risk management activities, please read "— Risk Management" and Item 7A "Quantitative and Qualitative Disclosures about Market Risk."

Public Offering of 8⅛% Senior Notes due 2016 and Reduction of Credit Facility Debt. On November 19, 2007, we closed an underwritten public offering of $125 million in principal amount of our 8⅛% Senior Notes due 2016. The notes, sold at a premium to par, were an additional issuance under our indenture dated February 7, 2006 and were offered under our effective shelf registration statement. We used net proceeds from the offering of $124 million to reduce outstanding indebtedness under our senior secured revolving credit facility, and for general company purposes.

Cantera Acquisition. We acquired Denver-based Cantera Natural Gas, LLC, or Cantera, on October 1, 2007, and closed the acquisition on October 19, 2007, for total consideration of $732.8 million, including working capital and other closing adjustments, consisting of $620.3 million in cash and 3,245,817 Class D units issued to the seller. We financed the cash consideration for the Cantera acquisition and related costs with borrowings of $300 million under our $550 million senior secured revolving credit facility and net proceeds from a $335 million private placement of 4,533,324 common units and 5,598,836 Class E units. The Cantera acquisition expanded our operations into the Rocky Mountains region. Cantera's principal assets are its 51.0% and 37.04% managing member interests, respectively, in Bighorn Gas Gathering, L.L.C., or Bighorn, and Fort Union Gas Gathering, L.L.C., or Fort Union, two firm gathering agreements with Fort Union and two firm capacity transportation agreements with Wyoming Interstate Gas Company. Bighorn and Fort Union operate natural gas gathering systems in Wyoming's Powder River Basin. At the time of the acquisition, the Bighorn system included approximately 238 miles of natural gas gathering pipelines, which deliver natural gas into the Fort Union system, and the Fort Union system consisted of an approximately 106-mile, 24" pipeline and a 62-mile loop. Cantera (now Copano Natural Gas/Rocky Mountains, L.L.C.), through its interests in Bighorn and Fort Union, is a leading gatherer of coal-bed methane gas in the Powder River Basin. Substantially all of Cantera's, Bighorn's and Fort Union's contract portfolios consist of fixed-fee contracts, which has resulted in a significant increase in the fixed-fee component of our contract mix.

Amended and Restated Revolving Credit Facility. On October 19, 2007 and in connection with the closing of the Cantera acquisition, we amended our senior secured revolving credit facility to, among other things, increase borrowing capacity under the credit facility from $200 million to $550 million and extend the maturity date to October 18, 2012. For a more detailed discussion of our credit facility, please read Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operation — Liquidity and Capital Resources — Description of Our Indebtedness."

Cimmarron Acquisition. On May 1, 2007, we acquired Cimmarron Gathering, LP, or Cimmarron, for approximately $97.2 million, including working capital and other closing adjustments, consisting of $43.2 million in cash and 1,579,409 Class C units issued to the sellers. We funded the cash portion of the purchase price for Cimmarron with borrowings under our senior secured revolving credit facility. At the time of the acquisition, Cimmarron's assets consisted primarily of approximately 430 miles of active natural gas gathering pipelines located primarily in central and eastern Oklahoma and in North Texas, of which approximately 69 miles were operated for crude oil gathering service, and included Cimmarron's 70% undivided interest in the Tri-County gathering system. Cimmarron also owned approximately 3,572 miles of inactive pipelines held for potential future development. In addition, in connection with our Cimmarron acquisition, we acquired the remaining 30% interest in the Tri-County gathering system for $15.3 million in cash, funded with cash on hand and borrowings under our senior secured revolving credit facility.

Business Strategy

Our management team is committed to exploiting new business opportunities associated with our existing assets, pursuing complementary acquisition and organic expansion opportunities, and managing our commodity risk exposure. Key elements of our strategy include:

- *Pursuing growth from our existing assets.* In many cases, our pipelines and processing plants have excess capacity, which provides us with opportunities to increase throughput volume with minimal incremental costs. We seek to increase cash flow from our existing assets by aggressively marketing our services to producers to connect new supplies of natural gas and increase volumes and utilization of capacity.

- *Pursuing complementary acquisitions and organic expansion opportunities.* We seek to use our acquisition and integration experience to continue to make complementary acquisitions of midstream assets in our operating areas that provide opportunities to expand either the acquired assets or our existing assets to increase utilization of capacity. We pursue acquisitions that we believe will allow us to capitalize on our existing infrastructure, personnel, and producer and customer relationships to strengthen our existing integrated package of services. Also, we seek to expand our assets where appropriate to meet increased demand for our midstream services.

- *Reducing the sensitivity of our cash flows to commodity price fluctuations.* Because of the volatility of natural gas and NGL prices, we attempt to structure our contracts in a manner that allows us to achieve positive gross margins in a variety of market conditions. Generally, we pursue arrangements under which the fee for our services is sufficient to provide us with positive operating margins irrespective of commodity prices. For example, we pursue processing arrangements at our Houston Central plant providing that we may elect to condition natural gas for a fee when processing is economically unattractive.

  In addition, our commodity risk management activities are designed to hedge our exposure to commodity price risk and allow us to meet our debt service, maintenance capital expenditure and similar requirements, and our distribution objectives, despite fluctuations in commodity prices. We intend to continue to manage our exposure to commodity prices in the future by entering into hedge transactions. Please read Item 7A, "Quantitative and Qualitative Disclosures about Market Risk."

- *Exploiting the operating flexibility of our assets.* We can modify the operation of our assets to maximize our cash flows. For example, our Houston Central plant has the ability to transition rapidly between processing and conditioning of natural gas, which provides us with significant benefits during periods when processing natural gas is not profitable. Also, our Houston Central and Paden plants each have ethane-rejection capability (the ability to reduce the ethane extracted from natural gas in processing), which we employ as market conditions warrant.

- *Expanding our geographic scope into new regions where our growth strategy can be applied.* We pursue opportunities to acquire assets in new regions where we believe growth opportunities are attractive and our business strategies could be applied. For example, with the Cantera acquisition in October 2007, we expanded into the Rocky Mountains region, and with the acquisition of ScissorTail Energy in August 2005, we expanded our operations to pursue opportunities in Oklahoma.

Our Operations

Our natural gas pipelines collect natural gas from wellheads or designated points near producing wells and deliver these volumes to third-party pipelines, our processing plants, third-party processing plants, local distribution companies, power generation facilities and industrial consumers. Our processing plants take delivery of natural gas from our gathering systems as well as third-party pipelines, and we treat the natural gas as needed to remove contaminants and process or condition it to extract mixed NGLs. After treating and conditioning or processing, we deliver the residue gas primarily to third-party pipelines through plant interconnects and sell the NGLs, in some cases after separating the NGLs into select component NGL products, to third parties. In addition, we operate NGL pipelines and a crude oil pipeline.

Our Operating Segments

Overview

We manage and operate our business in three geographic segments: Oklahoma, Texas and Rocky Mountains. Our operating segments are summarized in the following table:

Copano Energy Operating Segments

Segment	Primary Assets	Pipeline Miles[1] /Number of Processing Plants	Throughput/ Inlet Capacity[2][3]	Year Ended December 31, 2007 Average Throughput/ Inlet Volumes[2][3]	Year Ended December 31, 2007 Utilization of Capacity
Oklahoma	Natural Gas Pipelines	3,680	234,100	166,207	71%
	Processing Plants[4][5]	4	158,000	81,134	51%
	Crude Oil Pipelines	69	3,960	3,600	91%
Texas	Natural Gas Pipelines[6]	1,853	945,300	365,939	38%
	Processing Plants[7]	2	900,000	544,016	60%
	NGL Pipelines[8]	150	30,900	17,090	55%
Rocky Mountains	Natural Gas Pipelines[9]	463	1,140,000	821,434	72%

(1) Natural gas pipeline miles for Oklahoma and Texas exclude 2,996 miles and 576 miles, respectively, of inactive pipelines that are being held for potential future development.

(2) Many pipeline capacity values are based on current operating configurations and could be increased through additional compression, increased delivery meter capacity and/or other facility upgrades including, for example, larger dehydration capacity.

(3) Natural gas pipeline throughputs and inlet capacity are measured in Mcf/d. Crude oil and NGL pipeline throughputs are measured in Bbls/d.

(4) Includes the Southern Dome plant owned by Southern Dome, LLC, or Southern Dome, an unconsolidated limited liability company in which we own a majority interest. The plant is designed for operating capacity of 30,000 Mcf/d but is currently configured for 18,000 Mcf/d.

(5) In addition to transporting natural gas to our plants for processing, our Oklahoma segment delivers natural gas to six third-party plants in exchange for a portion of the product revenues. Average daily throughput volumes processed at third-party plants for our Oklahoma segment were 41,382 Mcf/d for the year ended December 31, 2007.

(6) Includes the 144-mile Webb/Duval system owned by Webb/Duval Gatherers, or Webb Duval, an unconsolidated partnership in which we hold a 62.5% interest.

(7) In addition to our Houston Central plant, our Texas segment includes a processing plant in Lake Charles, Louisiana, which we acquired as part of the Cantera acquisition. This plant, which has had no material operations since the acquisition, is managed by the personnel who manage our Texas operations.

(8) Includes our 46-mile Brenham NGL pipeline, which we lease from Kinder Morgan Texas Pipeline and expect to place into service in March 2008.

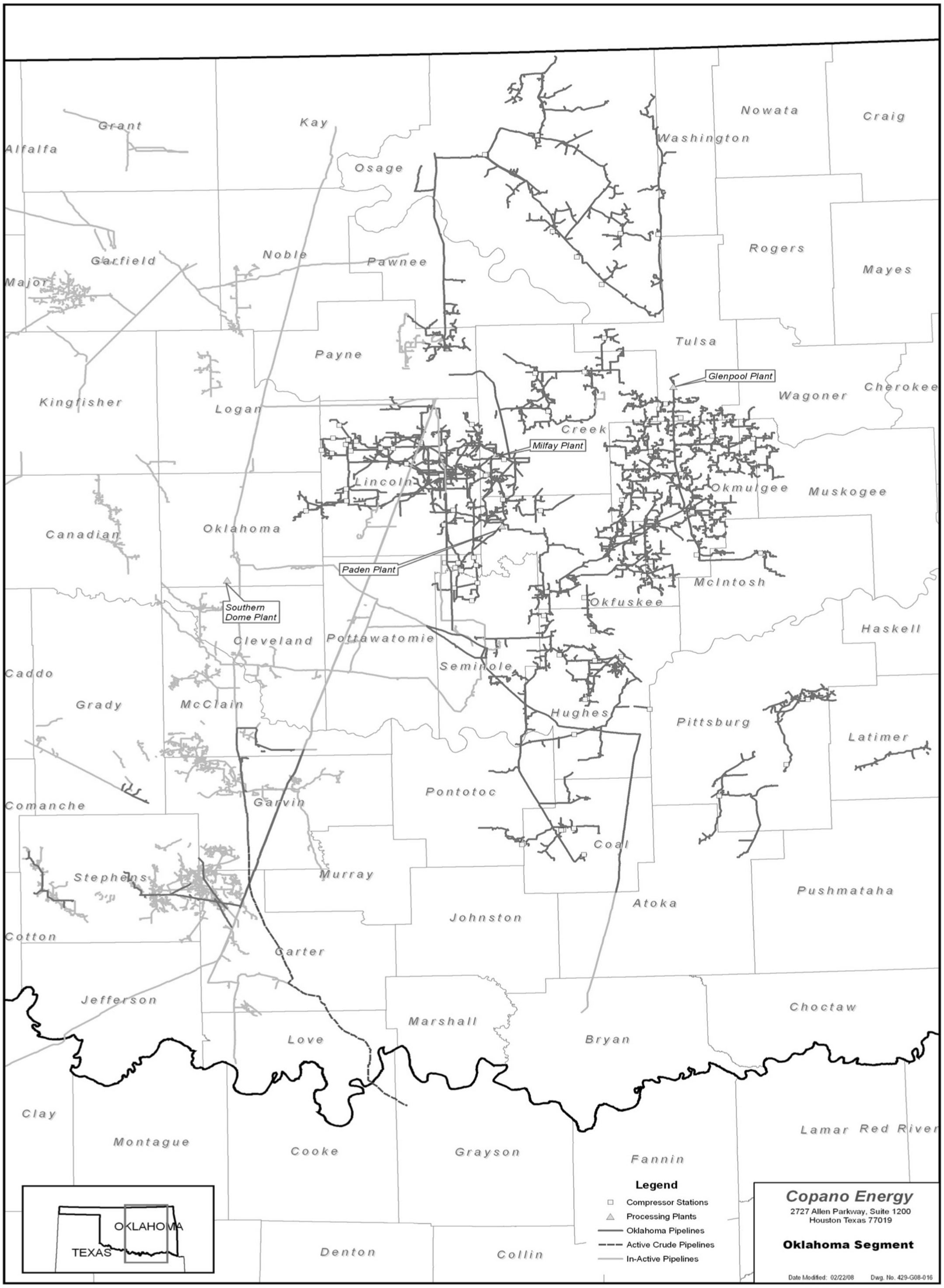
(9) Owned by Bighorn and Fort Union, in which we own 51.0% and 37.04% interests, respectively.

Oklahoma

Our Oklahoma segment operates in active natural gas producing areas in central and eastern Oklahoma and includes assets we acquired through our purchases of ScissorTail Energy, LLC, or ScissorTail, in August 2005 and Cimmarron in May 2007. These assets include:

- ten primarily low-pressure gathering systems occupying approximately 53,000 square miles;
- a crude oil pipeline; and
- four processing plants, one of which we own through our majority interest in Southern Dome.

The following map represents our Oklahoma segment:



The tables below provide summary descriptions of our Oklahoma pipeline systems and processing plants.

Oklahoma Pipelines

	Length (miles)	Diameter of Pipe (range)	Throughput Capacity(1)(2)	Year Ended December 31,2007 Average Throughput(1)(2)	Utilization of Capacity
Natural Gas Pipelines:					
Stroud	778	2″- 16″	102,000	90,743	89%
Osage	549	2″- 8″	26,000	18,883	73%
Milfay	351	2″- 16″	15,000	13,389	89%
Glenpool	1,015	2″- 10″	23,000	9,704	42%
Twin Rivers	537	2″- 12″	16,000	11,182	70%
Mountain(3)	164	2″- 20″	42,000	18,971	45%
Central Oklahoma(4)	190	2″- 12″	4,100	3,132	76%
Tomahawk(5)	96	3″- 10″	6,000	204	3%
Oklahoma Natural Gas Gathering	3,680		234,100	166,207	
Crude Oil Pipeline(6)	69	4″- 6″	3,960	3,600	91%

(1) Many capacity values are based on current operating configurations and could be increased through additional compression, increased delivery meter capacity or other facility upgrades.

(2) Natural gas pipeline throughputs are measured in Mcf/d. Crude oil throughputs are measured in Bbls/d.

(3) The Mountain system consists of three systems: Blue Mountain, Cyclone Mountain and Pine Mountain.

(4) Excludes 2,996 miles of inactive pipelines held for potential future development. Data reported for our Central Oklahoma system is only for the period from May 1, 2007 (the date of our Cimmarron acquisition) through December 31, 2007.

(5) The Tomahawk system was activated in April 2007 and is expected to be operational in March 2008.

(6) Data reported for our crude oil pipeline is only for the period from May 1, 2007 (the date of our Cimmarron acquisition) through December 31, 2007.

Oklahoma Processing

Processing Plants	Associated Gathering System	Facilities	Throughput Capacity(1)	Year Ended December 31, 2007 Average Inlet Volumes(1)	Utilization of Capacity	Average Processing Volumes NGLs	Residue
Paden	Stroud Tomahawk	Cryogenic/refrigeration Ethane rejection Nitrogen rejection(3)	100,000	54,347	54%	8,044	42,042
Milfay	Milfay	Propane refrigeration	15,000	12,428	83%	796	10,632
Glenpool	Glenpool	Cryogenic	25,000	9,266	37%	508	9,314
Southern Dome(2)	Southern Dome	Propane refrigeration	18,000	5,093	28%	244	4,706
Oklahoma Processing			158,000	81,134	52%	9,592	66,694

(1) Throughput capacity and inlet volumes are measured in Mcf/d. NGL volumes are measured in Bbls/d. Residue volumes are measured in MMBtu/d.

(2) We hold a majority interest in Southern Dome, which owns the Southern Dome plant. The plant is designed for operating capacity of 30,000 Mcf/d but is currently configured for 18,000 Mcf/d.

(3) Nitrogen rejection capability at our Paden plant is expected to become operational in March 2008 and will be limited to 60,000 Mcf/d.

In addition to transporting natural gas to our plants for processing, our Oklahoma segment delivers natural gas to six third-party plants in exchange for a portion of the product revenues. Average daily volumes processed at third-party plants for our Oklahoma segment were 41,382 Mcf/d for the year ended December 31, 2007.

Stroud System and Paden Processing Plant

The Stroud system is located in Payne, Lincoln, Oklahoma, Pottawatomie, Seminole and Okfuskee Counties, Oklahoma. In 2007, we delivered approximately 64% of the average throughput on this system to our Paden plant and the remainder to third-party processing plants in exchange for a share of the yield of NGLs and residue gas.

The Paden plant has a 60,000 Mcf/d turbo-expander cryogenic facility placed in service in June 2001, and a 40,000 Mcf/d refrigeration unit that was added in May 2007. The Paden plant also has the ability to reduce the ethane extracted from natural gas processed, or "ethane rejection" capability. This capability provides us an advantage when market prices or operating conditions make it more desirable to retain ethane within the gas stream. Field compression provides the necessary pressure at the plant inlet, eliminating the need for inlet compression. The plant also has inlet condensate facilities, including vapor recovery and condensate stabilization.

Wellhead production around the Paden plant includes natural gas high in nitrogen, which is inert and reduces the Btu value of residue gas. Because downstream pipeline quality specifications impose limitations on nitrogen content, we are installing a nitrogen rejection unit as part of our expansion of the Paden plant, which will allow us to process increased volumes of high-nitrogen natural gas while remaining in compliance with downstream pipeline specifications. Nitrogen rejection capability, which we expect will be operational in March 2008, will allow us to remove unwanted nitrogen from residue gas at the tailgate of the plant.

We deliver residue gas from the Paden plant to Enogex Inc. (a subsidiary of OGE Energy Corp.) and NGLs to ONEOK Hydrocarbon.

Osage System

The Osage system is located in Osage, Pawnee, Payne, Washington and Tulsa Counties, Oklahoma. Wellhead production on the Osage system tends to be lean, and the majority of the natural gas gathered on the system is not processed. We deliver lean gas from the Osage system to Enogex, ONEOK Gas Transmission ("OGT") and Keystone Gas. Natural gas we deliver to Keystone Gas is processed by a third-party processor and we receive a share of the NGLs and residue gas.

Milfay System and Processing Plant

The Milfay system is located in Tulsa, Creek, Payne, Lincoln and Okfuskee Counties, Oklahoma. We deliver natural gas gathered on the Milfay system to our Milfay and Paden plants. We deliver the residue gas from the Milfay plant into OGT and the NGLs to ONEOK Hydrocarbon.

Glenpool System and Processing Plant

The Glenpool system is located in Tulsa, Wagoner, Muskogee, McIntosh, Okfuskee, Okmulgee and Creek Counties, Oklahoma. Substantially all of the natural gas from the Glenpool system is delivered to our Glenpool plant. From the plant, we deliver the residue gas into either OGT or the American Electric Power Riverside power plant, and the NGLs to ONEOK Hydrocarbon.

Twin Rivers System

The Twin Rivers system is located in Okfuskee, Seminole, Hughes, Pontotoc and Coal Counties, Oklahoma. We deliver substantially all of the Twin Rivers system's volumes to a third-party plant for processing in exchange for a share of the NGLs and residue gas. We take the residue gas in-kind at the tailgate of Enogex's plant and sell the NGLs to Enogex.

Mountain Systems

The Mountain systems are located in Atoka, Pittsburg and Latimer Counties, in the Arkoma Basin, and include the Blue Mountain, Cyclone Mountain and Pine Mountain systems. Wellhead production on the Mountain systems is lean and generally does not require processing. We deliver natural gas from the Mountain systems to, among others, CenterPoint, Enogex and Natural Gas Pipeline Company of America, or NGPL.

Central Oklahoma System

The Central Oklahoma system, which we acquired as part of Cimmarron in May 2007, has provided us with added operating presence in natural gas producing regions in central Oklahoma. The Central Oklahoma system comprises five active gathering systems located in Garvin, Stephens, McClain, Oklahoma and Carter Counties, Oklahoma. We deliver gas gathered on the Central Oklahoma system to DCP Midstream.

Tomahawk System

The Tomahawk system, which we acquired as part of Cimmarron in May 2007, is expected to be operational in March 2008. The Tomahawk system is located in Atoka, Bryan, Coal, Hughes and Seminole Counties, Oklahoma. We deliver substantially all of the natural gas gathered on the Tomahawk system to the Paden plant.

Crude Oil Pipeline

The crude oil pipeline, which we acquired as part of Cimmarron in May 2007, is located in Love, Carter and Garvin Counties, Oklahoma, and Cooke and Grayson Counties, Texas. We use the crude oil line to transport and blend sweet and sour crude oil mix for sale to crude oil marketers, including High Sierra and SemCrude.

Southern Dome

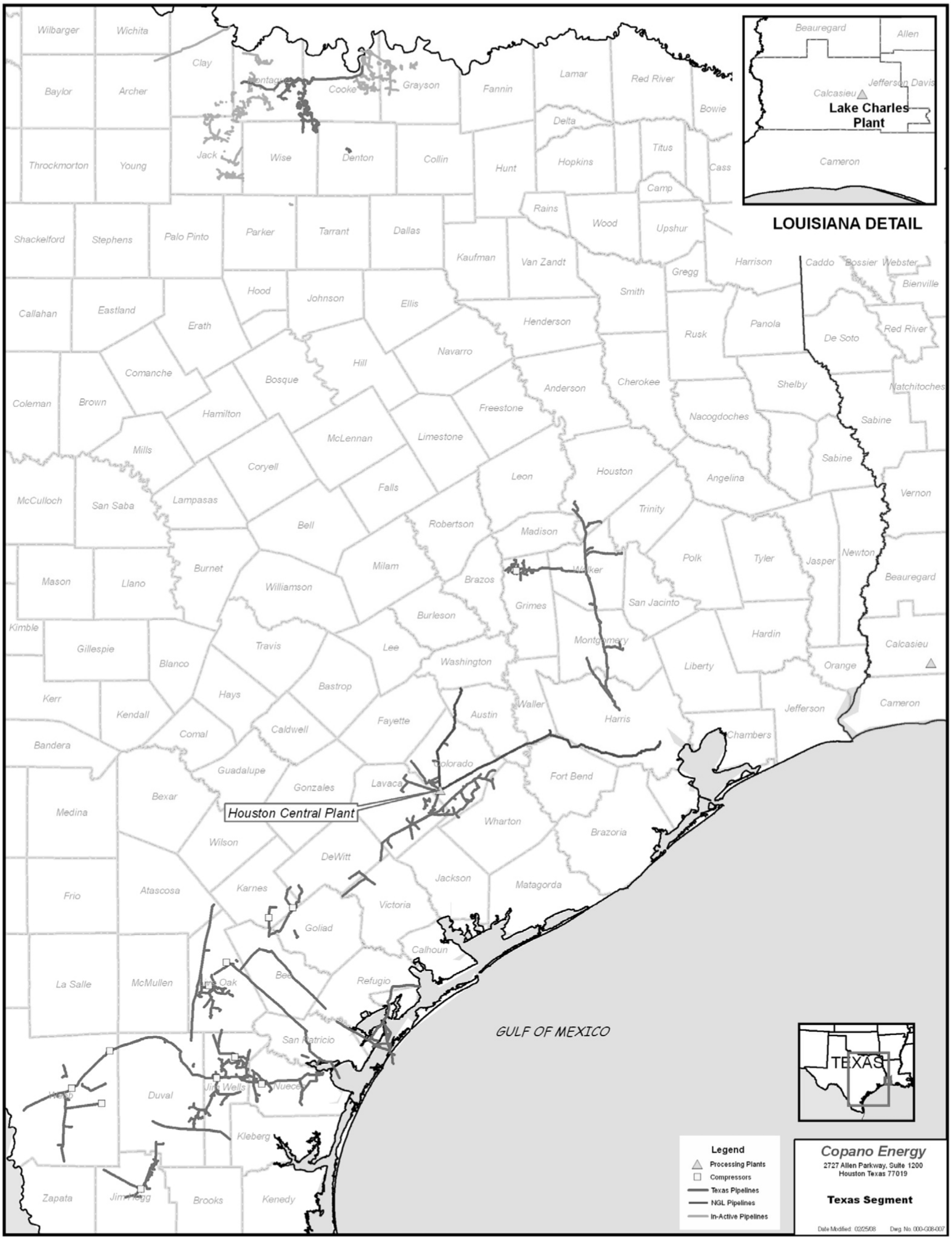
Through ScissorTail we own a majority interest in Southern Dome, LLC, or Southern Dome, which provides gathering and processing services within the Southern Dome prospect in the southern portion of Oklahoma County. We are the managing member of Southern Dome and serve as its operator. The Southern Dome plant began operating in April 2006. Southern Dome also operates a 3.4-mile gathering system owned by a single producer. Under a gas purchase and processing agreement between Southern Dome and this producer, substantially all of the natural gas from the gathering system is delivered to the Southern Dome processing plant. Southern Dome receives a fee for operating the gathering system and a percentage of the producer's residue gas and NGLs at the tailgate of the Southern Dome plant. We deliver the residue gas to OGT and sell the NGLs to various markets via trucks.

We are obligated to make 73% of capital contributions requested by Southern Dome up to a maximum commitment amount of $18.25 million. We are entitled to receive 69.5% of member distributions until "payout," which refers to a point at which we have received distributions equal to our capital contributions plus an 11% return. After payout occurs, we will be entitled to 50.1% of member distributions. As of December 31, 2007, we have made $13.5 million in aggregate capital contributions to Southern Dome and have received an aggregate of $2.0 million in member distributions.

Texas

Our Texas segment operates in southeastern and northern Texas and includes 1,853 miles of natural gas gathering and transmission pipelines, our Houston Central plant, located near Sheridan, Texas, and two NGL pipelines, one of which we lease from Kinder Morgan Texas Pipeline. Our Texas segment also includes the Lake Charles plant, located in Lake Charles, Louisiana, which we acquired as part of the Cantera acquisition. The Lake Charles plant, which has had no material operations since the acquisition, is managed by personnel who manage our Texas segment.

The following map represents our Texas segment:



The tables below provide summary descriptions of our Texas pipeline systems and processing plants.

Texas Pipelines

	Length (miles)	Diameter of Pipe (range)	Throughput Capacity[(1)(2)]	Year Ended December 31, 2007 Average Throughput[(1)(2)]	Utilization of Capacity
Natural Gas Pipelines:					
South Texas[(3)(4)]	1,102	2″- 20″	538,800	187,140	35%
Houston Central	313	2″- 12″	239,000	123,224	52%
Upper Gulf Coast	230	2″- 20″	139,000	36,728	26%
North Texas[(5)]	208	3″- 12″	28,500	18,847	66%
NGL Pipelines:					
Sheridan NGL Pipeline[(6)]	104	6″	30,900	17,090	55%
Brenham NGL Pipeline[(7)]	46	6″	—	—	—

(1) Many capacity values are based on current operating configurations and could be increased through additional compression, increased delivery meter capacity and/or other facility upgrades.

(2) Natural gas pipeline throughputs are measured in Mcf/d. NGL throughputs are measured in Bbls/d.

(3) Includes our Webb/Duval system owned by Webb Duval, an unconsolidated partnership in which we hold a 62.5% interest.

(4) Throughput volumes presented in the table are net of intercompany transactions.

(5) Excludes 576 miles of inactive pipelines held for potential future development. Data reported for our North Texas System is only for the period from May 1, 2007 (the date of our Cimmerron acquisition) through December 31, 2007.

(6) We use the eastern portion of our Sheridan NGL pipeline to transport butylene and the western portion to transport NGLs from our Houston Central plant to Enterprise Products Partners' Seminole pipeline. The central portion of our Sheridan NGL pipeline currently is inactive.

(7) We expect to place the Brenham NGL pipeline into service in March 2008.

Texas Processing

				Year Ended December 31, 2007			
						Average Processing Volumes[(1)(2)]	
Processing Plants	Associated Gathering System	Facilities	Throughput Capacity[(1)]	Average Inlet Volumes[(1)]	Utilization of Capacity	NGLs	Residue
Houston Central	Central Gulf Coast South Texas	Cryogenic/lean oil Ethane rejection	700,000	522,051	75%	16,295	483,933
Lake Charles[(3)]	—	Cryogenic	200,000	11,697(4)	6%	260[(4)]	11,439[(4)]

(1) Throughput capacity and inlet volumes are measured in Mcf/d. NGL volumes are measured in Bbls/d. Residue volumes are measured in MMBtu/d.

(2) Production from the Houston Central plant includes average daily volumes of 14,444 Bbls/d of ethane, propane, butane and natural gasoline mix delivered to the Sheridan NGL pipeline and 1,756 Bbls/d of stabilized condensate delivered to the TEPPCO crude oil pipeline.

(3) The Lake Charles plant, which has had no material operations since the acquisition, is managed by personnel who manage our Texas segment.

(4) Average inlet volumes and average processing volumes for the Lake Charles plant represent two days of activity in October 2007.

South Texas Systems

We deliver a substantial majority of the natural gas gathered on our systems in South Texas to our Houston Central plant for treating and processing, or conditioning, as needed. Our gathering systems in this area deliver to our Houston Central plant via the Laredo-to-Katy pipeline, a 30-inch diameter natural gas transmission pipeline system owned by Kinder Morgan Texas Pipeline, or KMTP, that extends along the Texas Gulf Coast from South Texas to Houston.

Our South Texas gathering systems that deliver natural gas to our Houston Central plant gather natural gas from fields located in Atascosa, Bee, DeWitt, Duval, Goliad, Jim Hogg, Jim Wells, Karnes, Live Oak, Nueces, Refugio and San Patricio Counties. Some of these systems also deliver to NGPL, DCP Midstream, and Houston Pipe Line Co., or HPL, an affiliate of Energy Transfer Partners, Tetco and ExxonMobil.

Among our systems in South Texas is the Webb/Duval gathering system, which is owned by Webb Duval, a general partnership that we operate and in which we hold a 62.5% interest. We operate the Webb/Duval system subject to the rights of the other partners, including rights to approve capital expenditures in excess of $0.1 million, financing arrangements by the partnership or any expansion projects associated with this system. In addition, each partner has the right to use its pro rata share of pipeline capacity on this system, subject to applicable ratable take and common purchaser statutes.

Our Copano Bay gathering system and Encinal Channel pipeline, which was placed in service in April 2007, operate onshore and offshore in Aransas, Nueces, Refugio and San Patricio Counties, Texas. These systems gather natural gas offshore in Aransas, Nueces and Copano Bays and from nearby onshore lands. Natural gas, produced water and condensate are separated at our Lamar and Estes Cove separation and dehydration facilities. We deliver natural gas from the Lamar facility to a third-party processing plant.

Houston Central Systems and Processing Plant

Our Houston Central gathering systems gather gas near the Houston Central plant in Colorado, DeWitt, Lavaca, Victoria and Wharton Counties, and deliver natural gas to the Houston Central plant directly, instead of via the Laredo-to-Katy pipeline. These systems can also take delivery of natural gas from Enterprise Products Partners and DCP Midstream.

Our Houston Central plant has approximately 700,000 Mcf/d of processing capacity and is the second largest and the most fuel efficient processing plant in South Texas. In addition to the conditioning capability described below, the Houston Central plant has:

- 8,029 horsepower of inlet compression, 1,340 of which we installed in 2007;
- 8,400 horsepower of tailgate compression;
- a 1,200 gallon-per-minute amine treating system for removal of carbon dioxide and low-level hydrogen sulfide;
- two 250,000 Mcf/d refrigerated lean oil trains;
- one 200,000 Mcf/d cryogenic turbo-expander train;
- a 25,000 Bbls/d NGL fractionation facility; and
- 882,000 gallons of storage capacity for propane, butane-natural gasoline mix and stabilized condensate.

We modified the Houston Central plant to provide natural gas conditioning capability in 2003, installing two new 700 horsepower, electric-driven compressors to provide propane refrigeration through the lean oil portion of the plant, which enables us to shut down our steam-driven refrigeration compressor when conditioning natural gas. We installed a third 700-horsepower, electric-driven compressor in January 2007. These compressors allow us to process gas only to the extent required to meet pipeline hydrocarbon dew point specifications, which we refer to as conditioning. Conditioning capability allows us to preserve a greater portion of the value of natural gas when processing is not profitable (in other words, when natural gas prices are high relative to NGL prices) because it allows us to:

- minimize the level of NGLs we remove from the natural gas stream while still meeting downstream pipeline hydrocarbon dew point specifications; and

- operate the plant more efficiently, with a substantial reduction in the amount of natural gas consumed as fuel.

When we elect to condition natural gas, typically our natural gas fuel consumption volumes are reduced by approximately 80%, while our average NGLs extracted are reduced approximately 91%. At the Houston Central plant, we process or condition natural gas delivered by the KMTP Laredo-to-Katy pipeline, which the plant straddles, and the pipelines in our Sheridan and Provident City gathering systems. The plant has tailgate interconnects with KMTP, HPL, Tennessee Gas Pipeline Company and Texas Eastern Transmission for redelivery of residue natural gas. In addition, we operate our Sheridan NGL pipeline, and anticipate operating our Brenham NGL pipeline beginning in March 2008, at the tailgate of the plant. TEPPCO Partners, L.P. operates a crude oil and stabilized condensate pipeline that runs from the tailgate of the plant to refineries in the greater Houston area.

The Houston Central plant was first constructed in 1965 by Shell and originally consisted of single refrigerated lean oil train and a fractionation facility. Shell expanded the plant in 1985, adding a second refrigerated lean oil train, and again in 1986, adding a cryogenic turbo expander train. The plant and related facilities are located on a 163-acre tract of land, which we lease under three long-term lease agreements.

Sheridan and Brenham NGL Pipelines. The western portion of the Sheridan NGL pipeline originates at the tailgate of the Houston Central plant and delivers NGLs into Enterprise Products Partners' Seminole Pipeline on the western side of Houston. The eastern portion of the Sheridan NGL pipeline originates at the Enterprise Products Partners' Almeda station in south Houston and delivers butylenes to the Shell Deer Park Plant on the Houston Ship Channel.

We expect to place the Brenham NGL pipeline, which originates at the tailgate of our Houston Central plant, into service in March 2008. We plan to use the Brenham NGL pipeline to deliver NGLs into the Enterprise Products Partners' Seminole pipeline near Brenham, Texas. We lease the Brenham NGL pipeline from Kinder Morgan Energy Partners, L.P. under a 5-year lease agreement that commenced February 1, 2006.

Our Commercial Relationship With Kinder Morgan Texas Pipeline. Kinder Morgan Texas Pipeline, or KMTP, owns a 2,500-mile natural gas pipeline system that extends along the Texas Gulf Coast from south Texas to Houston and primarily serves utility and industrial customers in the Houston, Beaumont and Port Arthur areas. KMTP sells and transports natural gas, and we use KMTP as a transporter because our Houston Central plant straddles its 30-inch-diameter KMTP Laredo-to-Katy pipeline. Using KMTP as a transporter allows us to move natural gas from our pipeline systems in south Texas and near the Texas Gulf Coast to our Houston Central plant and downstream markets. KMTP's pipeline also delivers to our Houston Central plant natural gas for its own account, which we refer to as "KMTP Gas." Under our contractual arrangements relating to KMTP Gas, we receive natural gas at our plant, process or condition the natural gas and sell the NGLs to third parties at market prices. For a discussion of our agreements with KMTP, please read Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operation — Our Contracts."

Upper Gulf Coast Systems

The Upper Gulf Coast systems are used for gathering, transportation and sales of natural gas to the north of Houston, Texas, in Houston, Walker, Grimes, Montgomery and Harris Counties. We also receive natural gas from interconnects with HPL, Vantex Gas Pipeline, a subsidiary of Energy Transfer Partners, KMTP, Atmos Pipeline — Texas and Texas Eastern Transmission. We deliver the natural gas gathered on these systems to multiple CenterPoint Energy city gates in Montgomery and Walker Counties, to Universal Natural Gas, a gas company that serves residential markets and Entergy's Lewis Creek generating plant, and to several industrial consumers.

North Texas Systems

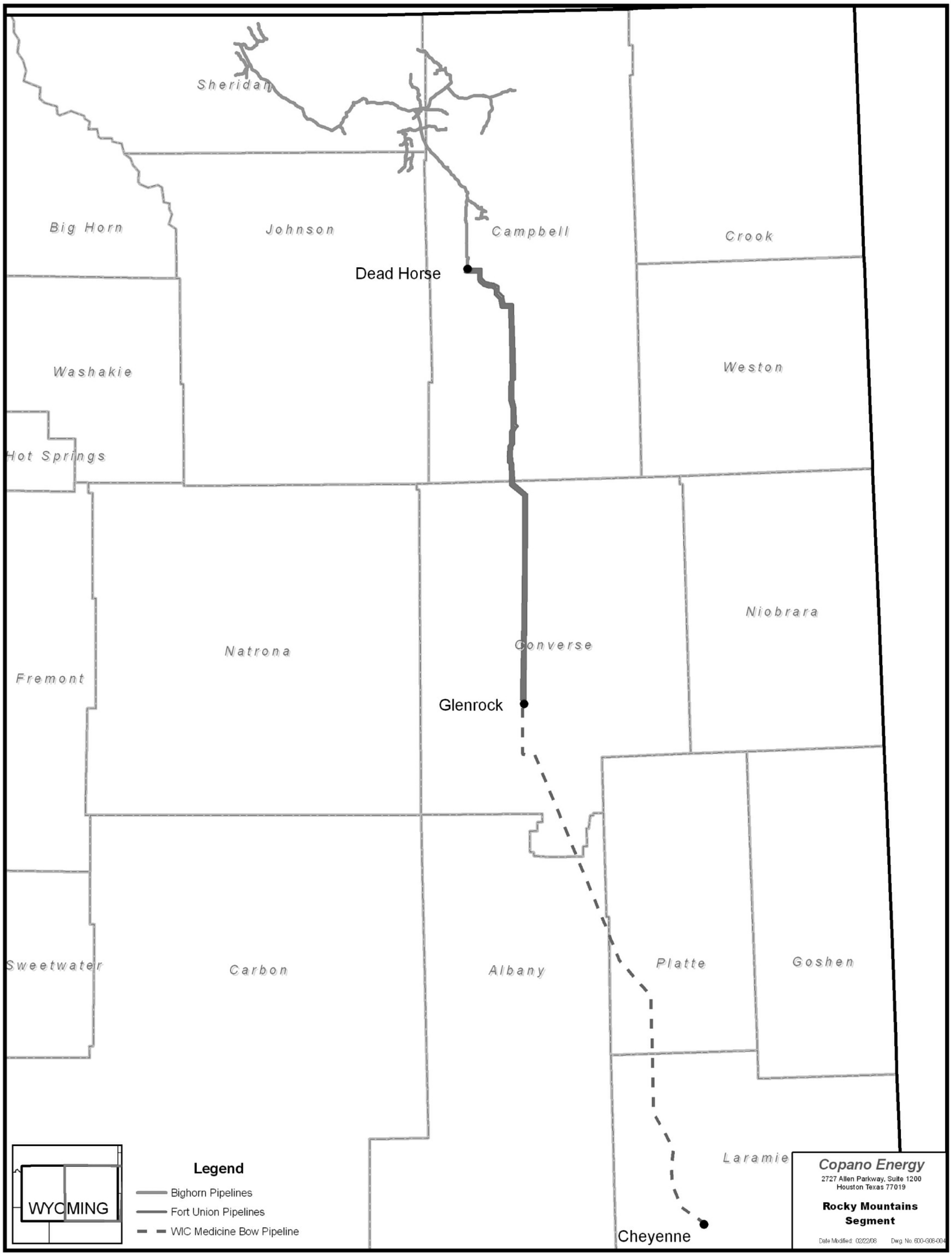
As part of our May 2007 Cimmarron acquisition, we acquired natural gas gathering pipelines in North Texas, which gather natural gas from the North Barnett Shale Play in Cooke, Denton, Johnson, Montague and Wise Counties. We deliver natural gas gathered in northern Texas to third-party pipelines, and a significant portion of the gas we deliver is processed at third-party processing plants. Our systems in North Texas have interconnects with Targa Resources, Atlas Pipeline, SemGas and NGPL.

Rocky Mountains

Our Rocky Mountains segment operates in coal-bed methane producing areas in Wyoming's Powder River Basin. We acquired the business and assets in this segment through our purchase of Denver-based Cantera in October 2007. The assets of Cantera (now Copano Natural Gas/Rocky Mountains, LLC) consist primarily of a 51.0% managing membership interest in Bighorn, a 37.04% managing membership interest in Fort Union, two firm gathering agreements with Fort Union and two firm capacity transportation agreements with Wyoming Interstate Gas Company ("WIC"). Two subsidiaries of ONEOK Partners own the remaining 49% membership interests in Bighorn and subsidiaries of Anadarko, Williams, and ONEOK Partners own the remaining 62.96% membership interests in Fort Union. Bighorn and Fort Union operate natural gas gathering systems in the Powder River Basin.

For the period from October 1, 2007 through December 31, 2007, total average throughput volumes for our Rocky Mountains segment were 232,169 Mcf/d. These volumes include volumes that we purchased for resale, volumes that we gathered utilizing our firm capacity gathering agreements with Fort Union and firm capacity volumes under our transportation agreements with WIC that we have released to producers in the Powder River Basin. These volumes exclude total average throughput volumes for the Bighorn and Fort Union systems, which are set forth below under "— Bighorn Gathering System" and "— Fort Union Gathering System."

The following map represents the assets of Bighorn and Fort Union:



Bighorn Gathering System

The Bighorn gas gathering system consists of approximately 251 miles of pipeline ranging from 6” to 24” in diameter and total throughput capacity of 300,000 Mcf/d, which could be increased to 600,000 Mcf/d through additional midpoint compression. The Bighorn system is located in Johnson, Sheridan and Campbell Counties, Wyoming. Bighorn provides low and high pressure natural gas gathering service to coal-bed methane producers in the Powder River Basin. Due to the lean nature of coal-bed methane wellhead production, gas gathered on the Bighorn system does not require processing and is delivered directly into the Fort Union gas gathering system at the southern terminus of the Bighorn system.

Although we serve as manager and field operator of Bighorn, certain significant business decisions with respect to Bighorn require the majority or unanimous approval of a management committee to which we have the right to appoint 50% of the committee members. Examples of some of these substantive business decisions include decisions with respect to significant expenditures or contractual commitments, annual budgets, material financings, the determination of excess cash for mandatory distribution to members, dispositions of assets or entry into new gathering agreements or amendments to existing gathering agreements, among others.

For the period from October 1, 2007 through December 31, 2007, total average throughput volumes for the Bighorn system were 216,584 Mcf/d.

Fort Union Gathering System

The Fort Union gas gathering system consists of two parallel 106-mile, 24" pipelines with total throughput capacity of 840,000 Mcf/d and the Medicine Bow amine treating facility with treating capacity of 300 gallons per minute, or GPM. This system, located in Campbell and Converse Counties, Wyoming, takes high pressure delivery of gas from the Bighorn system and also provides high pressure gas gathering services to producers that deliver gas directly or indirectly into the Fort Union system. Natural gas gathered from these producers is relatively high in carbon dioxide and, accordingly, must be treated at Fort Union's Medicine Bow treating facility in order to meet the quality specifications of downstream pipelines. Pipeline interconnects downstream from the Fort Union system include WIC, Kinder Morgan Interstate Gas Transportation Company ("KMIGT") and Colorado Interstate Gas Company ("CIG").

Fort Union is in the process of expanding its system by construction of a third 106-mile, 24" loop, which is expected to be operational in the second quarter of 2008. This system expansion is expected to increase the system's throughput capacity from 840,000 Mcf/d to 1.2 Bcf/d. Also, Fort Union has approved (subject to its members' final approval of the business terms) the installation of two additional amine treaters at its Medicine Bow treating facility, which will expand treating capacity from 300 GPM to 1,500 GPM and which are expected to be operational in the third quarter of 2008.

Fort Union gathers a majority of the gas across its system under standard firm gathering agreements between Fort Union and each of its four owners, including us. Pursuant to these agreements, each of Fort Union's owners is obligated to pay for a fixed quantity of firm gathering capacity (referred to as *demand capacity*) on the system, regardless of whether the owner uses the capacity. Also, each owner has the right to a portion of firm capacity on the system that is only paid for if utilized and is referred to as *variable capacity*. To the extent an owner does not use its allocated capacity or market it to third parties, it is available for use by the other owners. To the extent any capacity on the system is not utilized by the owners, it is available to third parties under interruptible gathering agreements. Beginning in 2009, a significant portion of the owners' demand capacity obligations terminate and that capacity becomes available to the owners as variable capacity. The firm gathering agreements between Fort Union and its owners terminate only upon mutual agreement of the parties.

Although we serve as the managing member of Fort Union, we do not operate the Fort Union system, nor do we provide certain administrative services. The Anadarko subsidiary acts as field operator and conducts all construction and field operations, while the ONEOK Partners subsidiary acts as administrative manager and provides gas control, contracts management and contract invoicing services. As managing member of Fort Union, we perform all other acts incidental to the management of Fort Union's business, including determining distributions to owners, executing gathering agreements, approving certain capital expenditures and monitoring the performance of the field operator and administrative manager, subject to the requirement that certain significant business decisions receive the 65% or unanimous approval of the owners. Examples of these significant business decisions include decisions with respect to significant expenditures or contractual commitments, annual budgets, material financings, dispositions of assets or amending the owners' firm gathering agreements, among others.

For the period from October 1, 2007 through December 31, 2007, total average throughput volumes for the Fort Union system were 604,850 Mcf/d, including an average of 216,584 Mcf/d delivered to Fort Union by Bighorn.

Producer Services

In addition to holding managing member interests in Bighorn and Fort Union, we provide services to a number of producers in the Powder River Basin, including producers who deliver gas into the Bighorn or Fort Union gathering systems. As part of our Cantera acquisition, we acquired two firm gathering agreements with Fort Union, which currently provide us with firm demand capacity on the Fort Union system of 198,150 Mcf/d and the right to utilize up to an additional 95,952 Mcf/d of firm variable system capacity. We also acquired two transportation agreements with WIC, which provide us with approximately 226,000 MMBtu/d of firm capacity on WIC's Medicine Bow lateral pipeline. Under these agreements, WIC transports natural gas from the terminus of the Fort Union system near Glenrock, Wyoming, as well as other receipt points, to the Cheyenne Hub, which provides a connection to five major interstate pipelines. Our WIC agreements extend through December 2019, with a right to renew for an additional five-year term. These agreements obligate us to pay for the capacity we hold on WIC's Medicine Bow lateral whether or not we use the capacity. We use our capacity on WIC and Fort Union to provide producers access to downstream interstate markets. In April 2007, we sold, or "released," the majority of our WIC capacity, and beginning in June 2008 all of our WIC capacity, to producers in the Powder River Basin through 2019.

Natural Gas Supply

We continually seek new supplies of natural gas, both to offset natural declines in production from connected wells and to increase throughput volume. We obtain new natural gas supplies in our operating areas by contracting for production from new wells, connecting new wells drilled on dedicated acreage or by obtaining natural gas supplies that were previously transported on other third-party gathering systems. We contract for supplies of natural gas from producers under a variety of contractual arrangements. The primary term of each contract varies significantly, ranging from one month to the life of the dedicated production. The terms of our natural gas supply contracts vary depending on, among other things, gas quality, pressure of natural gas produced relative to downstream pressure requirements, competitive environment at the time the contract is executed, and customer requirements. For a summary of our most common contractual arrangements, please read Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operation — Our Contracts."

We generally do not obtain reservoir engineering reports evaluating reserves dedicated to our pipeline systems due to the cost of such evaluations and the lack of publicly available producer reserve information. Accordingly, we do not have estimates of total reserves dedicated to our assets or the anticipated life of producing reserves.

Oklahoma

Our Oklahoma systems are located in areas that have experienced increased levels of drilling activity since 2003, which has led to increased volumes of natural gas through our Oklahoma segment's pipeline systems. Based on our discussions with producers in this area about their production plans, we expect to continue to expand our Oklahoma systems so that we can pursue newly developed natural gas supplies.

The five top natural gas producers by volume in our Oklahoma segment for 2007 collectively accounted for approximately 67% of the natural gas delivered to our Oklahoma systems during that period. Pursuant to a contract that extends through mid-year 2020, our largest Oklahoma producer by volume has dedicated to us all of its production within a 1.1 million acre area. We also have dedications from other producers covering their production within an aggregate 250,000 acres pursuant to contracts ending between 2009 and 2016.

Texas

Our Texas systems are located in areas that have experienced continued significant drilling activity, providing us with opportunities to access newly-developed natural gas supplies. The five top natural gas producers by volume in our Texas segment for 2007 collectively accounted for approximately 32% of the natural gas delivered to our Texas systems during that period.

Rocky Mountains

The Bighorn and Fort Union systems are located in the Powder River Basin, a major coal-bed methane exploration and development play in the United States. The Powder River Basin accounts for approximately eight out of 10 new coal-bed methane wells drilled with estimated recoverable reserves of 20 to 30 Tcf.

Under Fort Union's operating agreement, the owners of Fort Union established an area of mutual interest ("AMI") covering approximately 2.98 million acres in Converse, Campbell and Johnson Counties, Wyoming. Under the AMI, the owners have committed all gas production from the AMI to the Fort Union system up to the total capacity of the Fort Union system based on each owners total firm capacity rights.

The owners of Bighorn have established an approximately 3.8 million-acre area of mutual interest within the Powder River Basin of northern Wyoming and southern Montana, which provides that projects undertaken by the owners or their subsidiaries in the area of mutual interest must be conducted through Bighorn. Additionally, production from leases covering more than one million acres of land within the Powder River Basin has been dedicated to the Bighorn Gathering system by producers. Bighorn's largest Rocky Mountains producer by volume has dedicated to Bighorn approximately 300,000 acres pursuant to a contract that extends through 2019. We also have dedications from other producers within the same Bighorn dedicated area pursuant to contracts ending between 2011 and 2019.

Competition

The midstream natural gas industry is highly competitive. Competition in the midstream natural gas industry is based primarily on the reputation, efficiency, flexibility and reliability of the gatherer, the pricing arrangements offered by the gatherer, location of the gatherer's pipeline facilities and the gatherer's ability to offer a full range of services, including natural gas gathering, transportation, compression, dehydration and processing.

We face strong competition in acquiring new natural gas supplies. Our competitors include major interstate and intrastate pipelines and other natural gas gatherers that gather, process and market natural gas. Our competitors may have capital resources and control supplies of natural gas greater than ours.

We believe that offering an integrated package of services, while remaining flexible in the types of contractual arrangements that we offer producers, allows us to compete more effectively for new natural gas supplies in our operating regions.

Oklahoma

Substantially all of our Oklahoma systems offer low-pressure gathering service, which is attractive to producers. We have made significant investments in limited-emissions multi-stage compressors for our Oklahoma compression facilities, which has allowed for quicker permitting and installation, thereby allowing us to provide the pressure required by producers more efficiently. We believe this approach provides us a competitive advantage.

Our major competitors for natural gas supplies and markets in our Oklahoma segment include CenterPoint Field Services, DCP Midstream, LP, Oneok Field Services, Hiland Partners, Enogex, Mark West and Enerfin Resources Company.

Texas

Our major competitors for natural gas supplies and markets in our Texas segment include Enterprise Products Partners, Lobo Pipeline Company (an affiliate of ConocoPhillips), KMTP, DCP Midstream, Crosstex Energy, HPL, ExxonMobil, Targa Resources, Atlas Pipeline and Devon Energy. Competition for natural gas supplies is primarily based on the reputation, efficiency, flexibility and reliability of the gatherer, the pricing arrangements offered by the gatherer, the location of the gatherer's pipeline facilities and the ability of the gatherer to offer a full range of services, including compression, processing, conditioning and treating services.

We provide comprehensive services to natural gas producers, including natural gas gathering, transportation, compression, dehydration, treating, conditioning and processing. We believe our ability to furnish these services gives us an advantage in competing effectively for new supplies of natural gas because we can provide the services that producers, marketers and others require to connect their natural gas quickly and efficiently.

In addition, using centralized treating and processing facilities, we can in most cases attach producers that require these services more quickly and at a lower initial capital cost than our competitors due in part to the elimination of some field equipment and greater economies of scale at our Houston Central plant. For natural gas that exceeds the maximum carbon dioxide and NGL specifications for interconnecting pipelines and downstream markets, we believe that we offer treating, conditioning and other processing services on competitive terms.

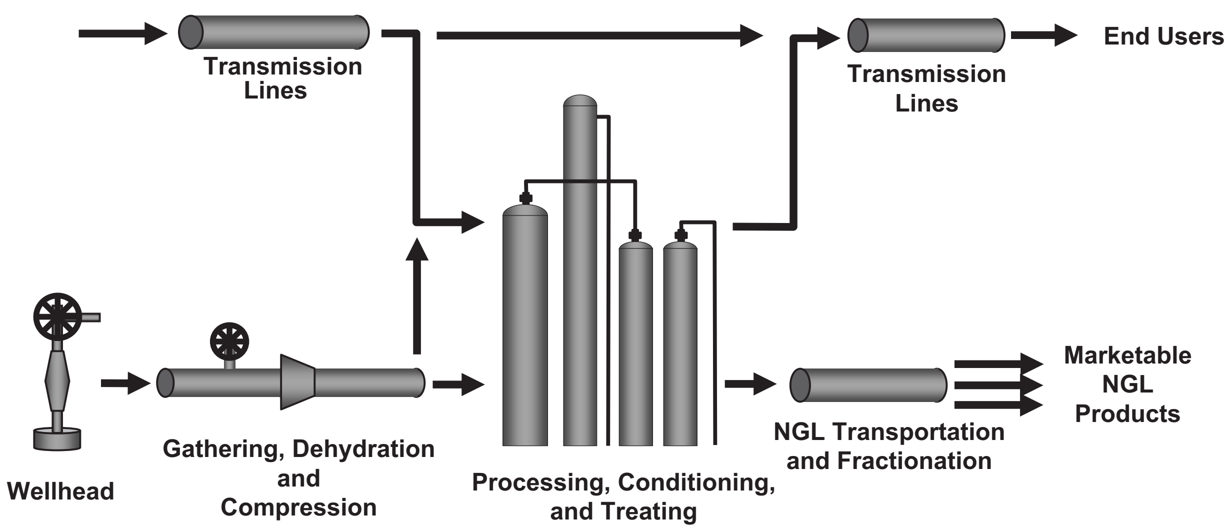
Rocky Mountains

Our major competitors for natural gas gathering supplies in our Rocky Mountains segment include Thunder Creek Gas Gathering, Bitter Creek Pipeline Company, Bear Paw Energy and Western Gas Resources. A significant portion of the gas on the Bighorn system is dedicated to Bighorn under long-term gas gathering agreements and, accordingly, is not available to competitors. Additionally, Fort Union's centralized amine treating facility and approved expansion provide Fort Union with a competitive advantage.

Industry Overview

The midstream natural gas industry is the link between the exploration and production of natural gas and the delivery of its components to end-use markets and consists of natural gas gathering, compression, dehydration, treating, conditioning, processing, fractionation and transportation.

We provide natural gas gathering, compression, dehydration, treating, conditioning, processing, fractionation and transportation services to our customers. These processes are illustrated in the following diagram.



- *Natural gas gathering.* The natural gas gathering process begins with the drilling of wells into gas bearing rock formations. Once a well has been completed, the well is connected to a gathering system. Gathering systems generally consist of a network of small-diameter pipelines that collect natural gas from points near producing wells and transport it to larger pipelines for further transmission.
- *Compression.* Gathering systems are operated at pressures that will maximize the total throughput from all connected wells. Because wells produce at progressively lower field pressures as they age, it becomes increasingly difficult to deliver the remaining production in the ground against the higher pressure that exists in the connected gathering system. Natural gas compression is a mechanical process in which a volume of gas at an existing pressure is compressed to a desired higher pressure, allowing gas that no longer naturally flows into a higher-pressure downstream pipeline to be brought to market. Field compression is typically used to allow a gathering system to operate at a lower pressure or provide sufficient discharge pressure to

deliver gas into a higher-pressure downstream pipeline. If field compression is not installed, then the remaining natural gas in the ground will not be produced because it will be unable to overcome the higher gathering system pressure. In contrast, if field compression is installed, a declining well can continue delivering natural gas.

- *Natural gas dehydration.* Natural gas is sometimes saturated with water, which must be removed because it can form ice and plug different parts of pipeline gathering and transportation systems and processing plants. Water in a natural gas stream can also cause corrosion when combined with carbon dioxide or hydrogen sulfide in natural gas, and condensed water in the pipeline can raise inlet pipeline pressure, causing a greater pressure drop downstream. Dehydration of natural gas helps to avoid these potential issues and to meet downstream pipeline and end-user gas quality standards.

- *Natural gas treating and blending.* Natural gas composition varies depending on the field, the formation and the reservoir from which it is produced. Natural gas from certain formations can be high in carbon dioxide or hydrogen sulfide, which may cause significant damage to pipelines and is generally not acceptable to end-users. To alleviate the potential adverse effects of these contaminants, many pipelines regularly inject corrosion inhibitors into the gas stream. Additionally, to render natural gas with high carbon dioxide or hydrogen sulfide levels marketable, pipelines may blend the gas with gas that contains low carbon dioxide or hydrogen sulfide levels, or arrange for treatment to remove carbon dioxide and hydrogen sulfide to levels that meet pipeline quality standards. Natural gas can also contain nitrogen, which lowers the heating value of natural gas and must be removed to meet pipeline specifications.

- *Amine treating.* The amine treating process involves a continuous circulation of a liquid chemical called amine that physically contacts with the natural gas. Amine has a chemical affinity for hydrogen sulfide and carbon dioxide that allows it to absorb these impurities from the gas. After mixing, gas and amine are separated, and the impurities are removed from the amine by heating. The treating plants are sized by the amine circulation capacity in terms of gallons per minute.

- *Natural gas processing.* Natural gas processing involves the separation of natural gas into pipeline quality natural gas and a mixed NGL stream. The principal component of natural gas is methane, but most natural gas also contains varying amounts of heavier hydrocarbon components, or NGLs. Natural gas is described as lean or rich depending on its content of NGLs. Most natural gas produced by a well is not suitable for long-haul pipeline transportation or commercial use because it contains NGLs and impurities. Natural gas processing not only removes unwanted NGLs that would interfere with pipeline transportation or use of the natural gas, but also extracts hydrocarbon liquids that can have higher value as NGLs. Removal and separation of individual hydrocarbons by processing is possible because of differences in weight, boiling point, vapor pressure and other physical characteristics.

- *Natural gas conditioning.* Conditioning of natural gas is the process by which NGLs are removed from the natural gas stream by lowering the hydrocarbon dew point sufficiently to meet downstream gas pipeline quality specifications. Although similar to natural gas processing, conditioning involves removing only an absolute minimum amount of NGLs (typically the components of pentane and heavier products) from the gas stream. Conditioning involves significantly higher temperatures than cryogenic processing and consumes less fuel. Conditioning capability is beneficial during periods of unfavorable processing margins.

- *NGL fractionation.* Fractionation is the process by which NGLs are further separated into individual, more valuable components. NGL fractionation facilities separate mixed NGL streams into discrete NGL products: ethane, propane, isobutane, normal butane, natural gasoline and stabilized condensate. Ethane is primarily used in the petrochemical industry as feedstock for ethylene, one of the basic building blocks for a wide range of plastics and other chemical products. Propane is used both as a petrochemical feedstock in the production of ethylene and propylene and as a heating fuel, an engine fuel and an industrial fuel. Isobutane is used principally to enhance the octane content of motor gasoline. Normal butane is used as a petrochemical feedstock in the production of ethylene and butylene (a key ingredient in synthetic rubber), as a blend stock for motor gasoline and to derive isobutane through isomerization. Natural gasoline, a mixture of pentanes and heavier hydrocarbons, is used primarily as motor gasoline blend stock or petrochemical feedstock.

Stabilized condensate is primarily used as a refinery feedstock for the production of motor gasoline and other products.

NGLs are fractionated by heating mixed NGL streams and passing them through a series of distillation towers. Fractionation takes advantage of the differing boiling points of the various NGL products. As the temperature of the NGL stream is increased, the lightest (lowest boiling point) NGL product boils off the top of the tower where it is condensed and routed to a pipeline or storage. The mixture from the bottom of the first tower is then moved into the next tower where the process is repeated and a different NGL product is separated and stored. This process is repeated until the NGLs have been separated into their components. Because the fractionation process uses large quantities of heat, fuel costs are a major component of the total cost of fractionation.

- *Natural gas transportation.* Natural gas transportation pipelines receive natural gas from other mainline transportation pipelines and gathering systems and deliver the natural gas to industrial end-users and utilities and to other pipelines.
- *NGL transportation.* NGLs are transported to market by means of pipelines, pressurized barges, rail car and tank trucks. The method of transportation utilized depends on, among other things, the existing resources of the transporter, the locations of the production points and the delivery points, cost-efficiency and the quantity of NGLs being transported. Pipelines are generally the most cost-efficient mode of transportation when large, consistent volumes of NGLs are to be delivered.

Risk Management

We are exposed to market risks, including changes in commodity prices and interest rates. We use financial instruments such as puts, calls, swaps and other derivatives to mitigate the effects of the identified risks. In general, we attempt to hedge risks related to the variability of future earnings and cash flows resulting from changes in applicable commodity prices or interest rates so that we can maintain cash flows sufficient to meet debt service, required capital expenditures, distribution objectives and similar requirements. Our risk management policy prohibits the use of derivative instruments for speculative purposes. For a more detailed discussion of our risk management activities, please read "— Recent Developments — Hedge Activity" and Item 7A, "Quantitative and Qualitative Disclosures about Market Risk."

Regulation

FERC Regulation of Intrastate Natural Gas Pipelines. We do not own any interstate natural gas pipelines, so the Federal Energy Regulatory Commission ("FERC") does not directly regulate any of our operations. However, FERC's regulation influences certain aspects of our business and the market for our products. In general, FERC has authority over natural gas companies that provide natural gas pipeline transportation services in interstate commerce and its authority to regulate those services includes:

- the certification and construction of new facilities;
- the review and approval of cost-based transportation rates;
- the extension or abandonment of services and facilities;
- the maintenance of accounts and records;
- the acquisition and disposition of facilities; and
- the initiation and discontinuation of services.

Under the Energy Policy Act of 2005, FERC possesses regulatory oversight over natural gas markets, including the purchase, sale and transportation activities of non-interstate pipelines and other natural gas market participants. The Commodity Futures Trading Commission, or the CFTC, also holds authority to monitor certain segments of the physical and futures energy commodities market pursuant to the Commodity Exchange Act. With regard to our physical purchases and sales of natural gas, NGLs and crude oil, our gathering or transportation of these energy commodities and any related hedging activities that we undertake, we are required to observe these anti-market manipulation laws and related regulations enforced by FERC and/or the CFTC. These agencies hold substantial enforcement authority, including the ability to assess civil penalties of up to $1 million per day per violation, to order disgorgement of profits and to recommend criminal penalties. Should we violate the anti-market manipulation laws and regulations, we could also be subject to related third party damage claims by, among others, sellers, royalty owners and taxing authorities.

FERC has adopted new market-monitoring and annual reporting regulations intended to increase the transparency of wholesale energy markets, to protect the integrity of such markets, and to improve FERC's ability to assess market forces and detect market manipulation. Although these regulations are not administratively final, the monitoring and annual reporting mandated by these regulations could require us to incur increased costs and administrative burdens. FERC has also proposed to require both interstate and certain major non-interstate pipelines to post, on a daily basis, capacity, scheduled flow information and actual flow information. Depending upon how the regulations define "major non-interstate pipeline," certain of our operations may also be subject to daily reporting requirements, which could subject us to further costs and administrative burdens. Our business, results of operations and financial condition could be adversely affected under these market monitoring and reporting requirements.

In recent years, the FERC has pursued pro-competitive policies in its regulation of interstate natural gas pipelines. However, we cannot assure you that the FERC will continue this approach as it considers matters such as pipeline rates and rules and policies that may affect rights of access to natural gas transportation capacity.

FERC Regulation of NGL Pipelines. We have interests in two NGL pipelines, both of which are located in Texas. We believe that these pipelines do not provide interstate service and that they are thus not subject to FERC jurisdiction under the ICA and the Energy Policy Act of 1992. Under the ICA, tariffs must be just and reasonable and not unduly discriminatory or confer any undue preference. We cannot guarantee that the jurisdictional status of our NGL facilities will remain unchanged, however. Should they be found jurisdictional, the FERC's rate-making methodologies may limit our ability to set rates based on our actual costs, may delay the use of rates that reflect increased costs, and we may be subject to potentially burdensome and expensive operational, reporting and other requirements. Any of the foregoing could adversely affect our business, revenues and cash flow.

FERC Regulation of Crude Oil Pipelines. With the acquisition of Cimmarron in May 2007, we now own a small, four-inch diameter crude oil pipeline, located in Texas and Oklahoma. Historically, this pipeline was thought to be a private carrier pipeline exempt from FERC jurisdiction. Upon further analysis, however, we believe that this pipeline provides interstate service subject to FERC jurisdiction under the Interstate Commerce Act ("ICA"). As a result, we may be required to file and maintain published tariffs, in which case the pipeline's rates would be required to be just and reasonable, and, when providing service, it could not confer any undue or unreasonable preference or prejudice. In any event, we expect compliance costs would be minimal.

Intrastate Natural Gas Pipeline Regulation. We own intrastate natural gas transmission facilities in Texas and Oklahoma. These facilities are subject to state safety, environmental and service regulation, but are generally not subject to rate regulation by the FERC.

To the extent that our intrastate pipelines transport natural gas in interstate commerce, the rates, terms and conditions of such transportation service are subject to FERC jurisdiction under Section 311 of the Natural Gas Policy Act. Section 311 requires, among other things, that rates for such interstate service, which may be established by the FERC or the applicable state agency, be "fair and equitable" and permits the FERC to approve terms and conditions of service.

Natural Gas Gathering Regulation. Section 1(b) of the Natural Gas Act ("NGA") exempts natural gas gathering facilities from the jurisdiction of the FERC. We own or hold interests in a number of natural gas pipeline systems in Texas, Oklahoma and Wyoming that we believe would meet the traditional tests FERC has used to establish a pipeline system's status as a non-jurisdictional gatherer. There is, however, no bright-line test for determining the jurisdictional status of pipeline facilities. Moreover, the distinction between FERC-regulated transmission services and federally unregulated gathering services is the subject of regular litigation, so the classification and regulation of some of our gathering facilities may be subject to change based on future determinations by FERC and the courts. Thus, we cannot guarantee that the jurisdictional status of our natural gas gathering facilities will remain unchanged.

In Texas, Oklahoma and Wyoming, the states in which our gathering operations take place, we are subject to state safety, environmental and service regulation. While we are not subject to direct state regulation of our gathering rates, we are required to offer gathering services on a non-discriminatory basis. In general, the non-discrimination requirement is monitored and enforced by each state based upon filed complaints.

We are also subject to state ratable take and common purchaser statutes in these states. Ratable take statutes generally require gatherers to take, without undue discrimination, natural gas production that may be tendered to the gatherer for handling. Similarly, common purchaser statutes generally require gatherers to purchase without discrimination in favor of one producer over another producer or one source of supply over another source of supply.

State Utility Regulation. Some of our operations in Texas are subject to the Texas Gas Utility Regulatory Act, as implemented by the Texas Railroad Commission ("TRRC"). Generally the TRRC is vested with authority to ensure that rates charged for natural gas sales or transportation services are just and reasonable. None of our operations in Oklahoma have historically been, or are currently, regulated by the Oklahoma Corporation Commission ("OCC") as public utilities. None of our operations in Wyoming have historically been, or are currently, regulated by the Wyoming Public Service Commission ("WPSC") as public utilities.

Sales of Natural Gas, Crude Oil and NGLs. The price at which we buy and sell natural gas currently is not subject to federal regulation and, for the most part, is not subject to state regulation. The prices at which we sell crude oil or NGLs are not subject to federal or state regulation.

Additional rules and legislation pertaining to these matters are considered or adopted from time to time. We cannot predict what effect, if any, such changes might have on our operations, but the industry could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes.

Environmental, Health and Safety Matters

The operation of pipelines, plants and other facilities for gathering, compressing, treating, processing or transporting natural gas, NGLs, crude oil and other products is subject to stringent and complex laws and regulations pertaining to health, safety and the environment. As an owner or operator of these facilities, we must comply with these laws and regulations at the federal, state and local levels. These laws and regulations can restrict or impact our business activities in many ways, such as:

- restricting the way we can handle or dispose of wastes;
- limiting or prohibiting construction and operating activities in environmentally sensitive areas such as wetlands, coastal regions, or areas inhabited by endangered species;
- requiring remedial action to mitigate pollution conditions caused by our operations or attributable to former operators; and
- enjoining the operations of facilities deemed in non-compliance with permits issued pursuant to such environmental laws and regulations.

Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial requirements and the issuance of orders enjoining future operations. Certain environmental statutes impose strict, joint and several liability for costs required to clean up and restore sites where wastes or other regulated substances have been disposed or otherwise released. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of substances or wastes into the environment.

We believe that our operations are in substantial compliance with applicable environmental laws and regulations and that compliance with existing federal, state and local environmental laws and regulations will not have a material adverse effect on our business, financial position or results of operations. We cannot assure you, however, that future events, such as changes in existing laws, the promulgation of new laws or the development or discovery of new facts or conditions will not cause us to incur significant costs. The trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment. As a result, there can be no assurance as to the amount or timing of future expenditures for environmental compliance or remediation, and actual future expenditures may be different from the amounts we currently anticipate.

The following is a summary of the more significant current environmental, health and safety laws and regulations to which our business operations are subject and for which compliance may require material capital expenditures or have a material adverse impact on our cash flow, results of operations or financial position:

Hazardous Waste. Our operations generate wastes, including some hazardous wastes, that are subject to the federal Resource Conservation and Recovery Act, as amended ("RCRA"), and comparable state laws, which impose detailed requirements for the handling, storage, treatment and disposal of hazardous and solid waste. RCRA currently exempts many crude oil and natural gas gathering and field processing wastes from classification as hazardous waste. Specifically, RCRA excludes from the definition of hazardous waste produced waters and other wastes associated with the exploration, development or production of crude oil and natural gas. However, these oil and gas exploration and production wastes may still be regulated under state law or the solid waste requirements of RCRA. Moreover, ordinary industrial wastes such as paint wastes, waste solvents, laboratory wastes and waste compressor oils may be regulated as hazardous waste. The transportation of crude oil or natural gas in pipelines may also generate some hazardous wastes that are subject to RCRA or comparable state law requirements.

Site Remediation. The Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended ("CERCLA"), also known as "Superfund," and comparable state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons responsible for the release of hazardous substances into the environment. Such classes of persons include the current and past owners or operators of sites where a hazardous substance was released and companies that disposed or arranged for disposal of hazardous substances at offsite locations such as landfills. Although petroleum and natural gas are excluded from CERCLA's definition of "hazardous substance," in the course of our ordinary operations we will generate wastes that may fall within the definition of a "hazardous substance." CERCLA authorizes the EPA and, in some cases, third parties, to take actions in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur. Under CERCLA, we could be subject to joint and several, strict liability for the costs of cleaning up and restoring sites where hazardous substances have been released, for damages to natural resources and for the costs of certain health studies.

We currently own or lease, and have in the past owned or leased, numerous properties that for many years have been used for the measurement, gathering, field compression and processing of natural gas. With the acquisition of Cimmarron, we now also own or lease properties that have been used for the gathering of crude oil for a number of years. Although we used operating and disposal practices that were standard in the industry at the time, petroleum hydrocarbons or wastes may have been disposed of or released on or under some properties owned or leased by us or on or under other locations where such substances have been taken for disposal. In fact, there is evidence that petroleum hydrocarbon spills or releases have occurred at some of the properties owned or leased by us. In addition, some of these properties have been operated by third parties or by previous owners whose treatment and disposal or release of petroleum hydrocarbons or wastes was not under our control. These properties and the substances disposed or released on them may be subject to CERCLA, RCRA and analogous state laws. Under such laws, we could be required to remove previously disposed wastes (including waste disposed of by prior owners or operators), remediate contaminated property (including groundwater contamination, whether from prior owners or operators or other historic activities or spills), or perform remedial plugging or pit closure operations to prevent future contamination.

Air Emissions. Our operations are subject to the federal Clean Air Act, as amended and comparable state laws and regulations. These laws and regulations regulate emissions of air pollutants from various industrial sources, including our processing plants and compressor stations and also impose various monitoring and reporting requirements. Such laws and regulations may require that we obtain pre-approval for the construction or modification of certain projects or facilities expected to produce air emissions or result in the increase of existing air emissions, obtain and comply with air permits containing various emissions and operational limitations, or utilize specific emission control technologies to limit emissions. Our failure to comply with these requirements could subject us to monetary penalties, injunctions, conditions or restrictions on operations and, potentially, criminal enforcement actions. We likely will be required to incur certain capital expenditures in the future for air pollution control equipment in connection with obtaining and maintaining operating permits and approvals for air emissions. We believe, however, that our operations will not be materially adversely affected by such requirements, and the requirements are not expected to be any more burdensome to us than to any other similarly situated companies.

Water Discharges. Our operations are subject to the Federal Water Pollution Control Act, as amended, also known as the Clean Water Act, and analogous state laws and regulations. These laws and regulations impose detailed requirements and strict controls regarding the discharge of pollutants into state and federal waters. The discharge of pollutants, including petroleum hydrocarbon discharges resulting from a spill or leak incident, is prohibited unless authorized by a permit or other agency approval. The Clean Water Act and regulations implemented thereunder also prohibit discharges of dredged and fill material in wetlands and other waters of the United States unless authorized by a permit. Any unpermitted release of pollutants from our pipelines or facilities could result in administrative, civil and criminal penalties and significant remedial obligations.

Pipeline Safety. Our pipelines are subject to regulation by the U.S. Department of Transportation ("DOT"), under the Natural Gas Pipeline Safety Act of 1968, as amended ("NGPSA") and the Hazardous Liquids Pipeline Safety Act of 1979, as amended ("HLPSA"), pursuant to which the DOT has established requirements relating to the design, installation, testing, construction, operation, replacement and management of pipeline facilities. The NGPSA covers the pipeline transportation of natural gas and other gases and the transportation and storage of liquefied natural gas, whereas the HLPSA covers the pipeline transportation of hazardous liquids including crude oil and petroleum products. Under both federal acts, any entity that owns or operates covered pipeline facilities is required to comply with the regulations under the NGPSA and HLPSA, to permit access to and allow copying of records and to make certain reports and provide information as required by the Secretary of Transportation. We believe that our pipeline operations are in substantial compliance with applicable existing NGPSA and HLPSA requirements; however, due to the possibility of new or amended laws and regulations or reinterpretation of existing laws and regulations, future compliance with the NGPSA and HLPSA could result in increased costs.

Our pipelines are also subject to regulation by the DOT under the Pipeline Safety Improvement Act of 2002, which was recently reauthorized and amended by the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006. The DOT, through the Office of Pipeline Safety, has established a series of rules which require pipeline operators to develop and implement integrity management programs for natural gas pipelines located in areas where the consequences of potential pipeline accidents pose the greatest risk to people and their property. Similar rules are also in place for operators of hazardous liquid pipelines. The DOT is required by the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006 to issue new regulations that set forth safety standards and reporting requirements applicable to low stress pipelines transporting hazardous liquids, including crude oil, NGLs and condensate. In addition, the DOT published a Notice of Proposed Rulemaking ("NPRM") in September 2006 that proposed to regulate certain onshore hazardous liquids gathering and low-stress pipeline systems found near "unusually sensitive areas," including non-populated areas requiring extra protection because of the presence of sole source drinking water resources, endangered species or other ecological resources. These safety standards may include applicable integrity management program requirements. While no new regulations have yet been finalized in response to the Safety Act of 2006 or the NPRM, final DOT rules are expected to be adopted during 2008. We do not expect these future regulations to have a material adverse effect on our operations. The TRRC and the OCC have adopted regulations similar to existing DOT regulations for intrastate natural gas and crude gathering and transmission lines while the Wyoming Public Service Commission has done the same only with respect to intrastate natural gas gathering and transmission lines. Compliance with existing rules has not had a material adverse effect on our operations in the past. However, we cannot assure you that this will continue in the future.

Employee Health and Safety. We are subject to the requirements of the federal Occupational Safety and Health Act, as amended ("OSHA") and comparable state laws that regulate the protection of the health and safety of workers. In addition, the OSHA hazard communication standard requires that certain information be maintained about hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens.

Anti-terrorism. We may be subject to future anti-terrorism requirements of the United States Department of Homeland Security ("DHS"). The DHS has issued its National Infrastructure Protection Plan ("NIPP") in an effort to "reduce vulnerability, deter threats, and minimize the consequences of attacks and other incidents." Although the precise parameters of DHS regulations and any related sector-specific requirements are not currently known, we have initially determined that the cost of compliance with such regulations is likely to be minimal. However, there can be no guarantee that final anti-terrorism rules that might be applicable to our facilities will not impose substantial costs and administrative burdens on our operations, adversely affecting our business.

Other Laws and Regulations. Recent studies have suggested that emissions of certain gases may be contributing to warming of the earth's atmosphere. In response to these studies, many foreign nations have agreed to limit emissions of "greenhouse gases", pursuant to the United Nations Framework Convention on Climate Change, also known as the "Kyoto Protocol". Methane, a primary component of natural gas, and carbon dioxide, a byproduct of the burning of fossil fuels, are "greenhouse gases" regulated by the Kyoto Protocol. Although the United States is not participating in the Kyoto Protocol, recent sessions of Congress have considered climate control legislation, with multiple bills having already been introduced in the Senate that propose to restrict greenhouse gas emissions. Several states have already adopted legislation, regulations and/or regulatory initiatives to reduce emissions of greenhouse gases. For instance, California adopted the "California Global Warming Solutions Act of 2006", which requires the California Air Resources Board to achieve a 25% reduction in emissions of greenhouse gases from sources in California by 2020. Additionally, the U.S. Supreme Court, in Massachusetts, et al. v. EPA, has required the EPA to justify its refusal to regulate carbon dioxide emissions under the Clean Air Act. Passage of climate control legislation by Congress or a revised ruling by the EPA could result in federal regulation of carbon dioxide emissions and other greenhouse gases. Such restrictions could have many adverse effects on our business including limiting our ability to process natural gas, increasing our expenses and lowering the demand for our services.

Office Facilities

We occupy approximately 31,000 square feet of space at our executive offices in Houston, Texas under a lease expiring on May 31, 2012. At the expiration of the primary term, we have an option to renew this lease for an additional five years at then-prevailing market rates. We also occupy approximately 10,000 square feet of office space in Tulsa, Oklahoma, which serves as the executive offices for our Oklahoma employees. The Tulsa lease expires November 30, 2010 and provides us with a five-year renewal option at then-prevailing market rates. We occupy approximately 13,300 square feet of space in Englewood, Colorado, which serves as the executive offices for our Rocky Mountains employees. The Englewood lease expires September 30, 2008. We also lease property or facilities for some of our field offices. While we may require additional office space as our business expands, we believe that our existing facilities are adequate to meet our needs for the immediate future, and that additional facilities will be available on commercially reasonable terms as needed.

Employees

As of December 31, 2007, we, through our subsidiaries, CPNO Services, L.P. and ScissorTail, had 318 full-time employees and 4 part-time employees and Copano/Operations, Inc. ("Copano Operations") employed 14 full-time employees on our behalf. None of our employees are covered by collective bargaining agreements. We consider our relations with these employees, with Copano Operations and with those Copano Operations' employees providing services to us to be good. In exchange for providing general and administrative services to us, including employing certain personnel on our behalf, we are required to reimburse Copano Operations for its costs and expenses. To the extent these employees provide services on our behalf, we refer to them as our employees. For more information concerning our arrangement with Copano Operations, please read Note 9, "Related Party Transactions," to the consolidated financial statements beginning on Page F-1 of this report.

Available Information

We file annual, quarterly and other reports and other information with the Securities and Exchange Commission ("SEC") under the Securities Exchange Act of 1934 (the "Exchange Act"). You may read and copy any materials that we file with the SEC at the SEC's Public Reference Room at 100 F Street, NE, Washington, DC 20549. You may obtain additional information about the Public Reference Room by calling the SEC at 1-800-SEC-0330. In addition, the SEC maintains an Internet site (http://www.sec.gov) that contains reports, proxy and information statements and other information regarding issuers that file electronically with the SEC, including us.

We also make available free of charge on or through our Internet website (http://www.copanoenergy.com) or through our Investor Relations group (713-621-9547) our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and other information statements and, if applicable, amendments to those reports filed or furnished pursuant to Section 13(a) of the Exchange Act, as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC.

Item 1A. *Risk Factors*

In addition to the factors discussed elsewhere in this Annual Report, including the financial statements and related notes, you should consider carefully the risks and uncertainties described below, which could materially adversely affect our business, financial condition and results of operations. While these are the risks and uncertainties we believe are most important, you should know that they are not the only risks or uncertainties facing us or which may adversely affect our business. If any of the following risks or uncertainties were to occur, our business, financial condition or results of operation could be adversely affected. Additional risks and uncertainties not presently known to us or that we currently deem immaterial also may impair our business operations and financial condition.

Risks Related to Our Business

We may not have sufficient cash from operations each quarter to pay our minimum quarterly distribution following establishment of cash reserves and payment of fees and expenses.

We may not have sufficient available cash each quarter to pay the minimum quarterly distribution. Under the terms of our limited liability company agreement, we must pay our operations and maintenance expenses and set aside any cash reserve amounts before making a distribution to our unitholders. The amount of cash we can distribute on our common units principally depends upon the amount of cash we generate from our operations, which will fluctuate from quarter to quarter based on, among other things:

- the amount of natural gas gathered and transported on our pipelines;
- the amount and NGL content of the natural gas we process;
- the price of natural gas, NGLs and crude oil;
- the relationship between natural gas and NGL prices;
- the level of our operating costs and the impact of inflation on those costs;
- the weather in our operating areas;
- the level of competition from other midstream energy companies; and
- the fees we charge and the margins we realize for our services.

In addition, the actual amount of cash we will have available for distribution will depend on other factors, some of which are beyond our control, including:

- the level of capital expenditures we make;
- the cost of acquisitions, if any;
- our debt service requirements;
- fluctuations in our working capital needs;
- restrictions on distributions contained in our senior secured revolving credit facility and the indenture governing our 8⅛% Senior Notes due 2016 (“Senior Notes”);

- our ability to make working capital borrowings under a credit facility that are eligible to be used to pay distributions;
- prevailing economic conditions; and
- the amount of cash reserves established by our Board of Directors for the proper conduct of our business.

The amount of cash we have available for distribution depends primarily upon our cash flow, including cash flow from financial reserves, and is not solely a function of profitability, which will be affected by non-cash items. As a result, we may make cash distributions during periods when we record losses and may not make cash distributions during periods when we record net income.

To the extent that we make acquisitions in the future and our acquisitions do not perform as expected, our future financial performance may be negatively impacted.

Our business strategy includes making acquisitions that we anticipate would increase the cash available for distribution to our unitholders. As a result, from time to time, we evaluate and pursue assets and businesses that we believe complement our existing operations or expand our operations into new regions where our growth strategy can be applied. In 2007, we acquired assets in north Texas and Oklahoma, through our acquisition of Cimmarron, and acquired Cantera, which expanded our operations into the Rocky Mountains region. We cannot assure you that we will be able to complete acquisitions in the future or achieve the desired results from the Cimmarron and Cantera acquisitions or any other acquisitions we complete in the future. In addition, failure to successfully assimilate our acquisitions could adversely affect our financial condition and results of operations.

Our acquisitions potentially involve numerous risks, including:

- operating a significantly larger combined organization and adding operations;
- difficulties in the assimilation of the assets and operations of the acquired businesses, especially if the assets acquired are in a new business segment or geographic area;
- the risk that natural gas reserves expected to support the acquired assets may not be of the anticipated magnitude or may not be developed as anticipated;
- the loss of significant producers or markets or key employees from the acquired businesses;
- the diversion of management's attention from other business concerns;
- the failure to realize expected profitability or growth;
- the failure to realize any expected synergies and cost savings;
- coordinating geographically disparate organizations, systems and facilities; and
- coordinating or consolidating corporate and administrative functions.

Further, unexpected costs and challenges may arise whenever businesses with different operations or management are combined, and we may experience unanticipated delays in realizing the benefits of an acquisition. If we consummate any future acquisition, our capitalization and results of operation may change significantly, and you may not have the opportunity to evaluate the economic, financial and other relevant information that we will consider in evaluating future acquisitions.

Our acquisitions could expose us to potential significant liabilities.

We generally assume the liabilities of an entity that we purchase and may assume certain liabilities relating to assets that we acquire, including unknown and contingent liabilities. We perform due diligence in connection with our acquisitions and attempt to verify the representations of the sellers, but there may be pending, threatened, contemplated or contingent claims related to environmental, title, regulatory, litigation or other matters of which we are unaware. Although we may have indemnification claims against sellers for certain of these liabilities, our right to indemnification is generally limited in amount and to claims made within a specified time period. For example, we have the right to indemnification from the sellers of Cimmarron and Cantera for certain liabilities, but the indemnification is also generally limited in amount and to claims made within a specified time period. Because we assume certain liabilities in connection with our acquisitions, there is a risk that we could ultimately be liable for unknown obligations of the acquired entity or relating to the acquired assets, which could materially adversely affect our operations and financial condition.

We may not be able to fully execute our business strategy if we encounter illiquid capital markets.

One component of our business strategy contemplates pursuing opportunities to acquire assets in new regions where we believe growth opportunities are attractive and our business strategies could be applied. We regularly consider and enter into discussions regarding strategic transactions that we believe will present opportunities to pursue our growth strategy.

We will require substantial new capital to finance strategic acquisitions. Any limitations on our access to capital will impair our ability to execute this component of our growth strategy. If the cost of such capital becomes too expensive, our ability to develop or acquire accretive assets will be limited. We may not be able to raise the necessary funds on satisfactory terms, if at all. The primary factors that influence our cost of capital include market conditions and offering or borrowing costs such as interest rates or underwriting discounts.

Our substantial indebtedness could limit our operating flexibility and impair our ability to fulfill our debt obligations.

We have substantial indebtedness. As of December 31, 2007 and in addition to liabilities we incurred as a result of our risk management activities, we had:

- total indebtedness of $630.0 million, including indebtedness associated with our Senior Notes and our senior secured revolving credit facility; and
- availability under our senior secured revolving credit facility of approximately $270.0 million.

Subject to the restrictions governing our existing indebtedness and other financial obligations, we may incur significant additional indebtedness and other financial obligations in the future. Our substantial indebtedness and other financial obligations could have important consequences to you. For example, it could:

- make it more difficult for us to satisfy our obligations with respect to our indebtedness;
- impair our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions, general company purposes or other purposes;
- result in higher interest expense in the event of increases in interest rates to the extent that any of our debt is subject to variable rates of interest;
- have a material adverse effect on us if we fail to comply with financial and restrictive covenants in our debt agreements and an event of default occurs as a result of that failure that is not cured or waived;
- require us to dedicate a substantial portion of our cash flow to payments on our indebtedness and other financial obligations, thereby reducing the availability of our cash flow to fund working capital, capital expenditures and other general company requirements;
- limit our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate; and
- place us at a competitive disadvantage compared to any competitors that have proportionately less debt.

If we are unable to meet our debt service obligations and other financial obligations, we could be forced to restructure or refinance our indebtedness, seek additional equity capital or sell assets. We may be unable to obtain such refinancing or equity capital or sell assets on satisfactory terms, if at all.

Restrictive covenants in the agreements governing our indebtedness may reduce our operating flexibility.

The indenture governing our outstanding Senior Notes contains various covenants that limit our ability and the ability of specified subsidiaries to, among other things:

- sell assets;
- pay distributions on, redeem or repurchase our equity interests or redeem or repurchase our subordinated debt, if any;
- make investments;
- incur or guarantee additional indebtedness or issue preferred units;
- create or incur certain liens;
- enter into agreements that restrict distributions or other payments from our restricted subsidiaries to us;
- consolidate, merge or transfer all or substantially all of our assets;
- engage in transactions with affiliates;
- create unrestricted subsidiaries; and
- enter into sale and leaseback transactions.

Our senior secured revolving credit facility contains similar covenants as well as covenants that require us to maintain specified financial ratios and satisfy other financial conditions. The restrictive covenants in our indenture and in the senior secured revolving credit facility could limit our ability and the ability of our subsidiaries to obtain future financings, make needed capital expenditures, withstand a future downturn in our business or the economy in general, conduct operations or otherwise take advantage of business opportunities that may arise. We may be unable to comply with these covenants. Any future breach of any of these covenants could result in a default under the terms of the indenture or our senior secured revolving credit facility, which could result in acceleration of our debt and other financial obligations. If we were unable to repay those amounts, the lenders could initiate a bankruptcy proceeding or liquidation proceeding or proceed against any collateral.

Because of the natural decline in production from existing wells in our operating regions, our future success depends on our ability to continually obtain new sources of natural gas supply, which depends in part on certain factors beyond our control. Any decrease in supplies of natural gas could adversely affect our revenues and operating income.

Our gathering and transmission pipeline systems are connected to natural gas fields and wells, for which the production will naturally decline over time, which means that our cash flows associated with these wells will also decline over time. To maintain or increase throughput levels on our pipeline systems and our processing plants, we must continually obtain new natural gas supplies. We may not be able to obtain additional contracts for natural gas supplies. The primary factors affecting our ability to connect new supplies of natural gas and attract new customers to our gathering and transmission lines include: (i) the level of successful drilling activity near our gathering systems and (ii) our ability to compete for the attachment of such additional volumes to our systems.

Fluctuations in energy prices can greatly affect production rates and investments by third parties in the development of new natural gas reserves. Drilling activity generally decreases as natural gas prices decrease. We have no control over the level of drilling activity in the areas of our operations, the amount of reserves underlying the wells or the rate at which production from a well will decline. In addition, we have no control over producers or their production decisions, which are affected by, among other things, prevailing and projected energy prices, rig availability, demand for hydrocarbons, the level of reserves, geological considerations, governmental regulations and the availability and cost of capital.

We face strong competition in acquiring new natural gas supplies. Competitors to our pipeline operations include major interstate and intrastate pipelines, and other natural gas gatherers. Competition for natural gas supplies is primarily based on the location of pipeline facilities, pricing arrangements, reputation, efficiency, flexibility and reliability. Our major competitors for natural gas supplies and markets in our Texas segment include Enterprise Products Partners, Lobo Pipeline Company, KMTP, DCP Midstream, Crosstex Energy, ExxonMobil, HPL, Targa Resources, Atlas Pipeline and Devon Energy. The primary competitors in our Oklahoma segment include CenterPoint Field Services, DCP Midstream, ONEOK Field Services, Enogex, Enerfin, Hiland Partners and MarkWest. The primary competitors in our Rocky Mountains segment include Thunder Creek Gas Gathering, Bitter Creek Pipeline Company, Bear Paw Energy and Western Gas Resources. A number of our competitors are larger organizations than we are.

If we are unable to maintain or increase the throughput on our pipeline systems because of decreased drilling activity in the areas in which we operate, decreased production from the wells connected to our systems or an inability to connect new supplies of gas and attract new customers to our gathering and transmission lines, then our business and financial results or our ability to achieve our growth strategy could be materially adversely affected. Please read Item 1, "Business — Natural Gas Supply" in this Annual Report for more information on our access to natural gas supplies.

We rely on KMTP's Laredo-to-Katy pipeline to transport natural gas to our Houston Central processing plant, and an NGL pipeline owned by ONEOK Hydrocarbon to transport NGLs from our Paden processing plant. If one of these pipelines were to become unavailable, our cash flows, results of operations and financial condition could be adversely affected.

Our ability to contract for natural gas supplies in the Texas region will often depend on our ability to deliver gas to our Houston Central plant and downstream markets, and we rely on KMTP's Laredo-to-Katy pipeline to transport natural gas from our South Texas systems to the Houston Central plant. For the year ended December 31, 2007, approximately 42% of the total natural gas delivered by our Texas segment was delivered to KMTP, and approximately 76% of the natural gas volumes processed or conditioned at our Houston Central plant were delivered to the plant through the KMTP Laredo-to-Katy pipeline.

If KMTP's pipeline were to become unavailable for any reason, the volumes transported to our Houston Central plant would be reduced substantially, and our revenues and operating income from our Texas processing business could be adversely affected. In addition, much of the natural gas we gather in South Texas contains NGLs that must be removed in order to meet downstream market quality specifications. If we were unable to ship such natural gas to our Houston Central plant for processing or conditioning, and, if required, treating, we would need to arrange for an alternate means of removing NGLs and transport through other pipelines. Alternatively, we might be required to lease smaller treating and processing facilities so that we could treat and condition or process natural gas as needed to meet pipeline quality specifications.

In addition, we rely on ONEOK Hydrocarbon to take delivery of NGLs from our Paden and Milfay plants in Oklahoma. If ONEOK Hydrocarbon's NGL pipeline were to be come unavailable, we would be required to run one or both of these plants in a reduced operating mode and make arrangements to re-route a portion of the natural gas we receive for processing to third-party plants, as well as make arrangements to transport NGLs to market by truck. A prolonged interruption or reduction of service on ONEOK Hydrocarbon's NGL pipeline could hinder our ability to contract for natural gas supplies, which in turn would adversely affect our revenues and operating income.

We generally do not obtain reservoir engineering reports evaluating reserves dedicated to our pipeline systems; therefore, volumes of natural gas transported on our pipeline systems in the future could be less than we anticipate, which may cause our revenues and operating income to be less than we expect.

We generally do not obtain reservoir engineering reports evaluating natural gas reserves connected to our pipeline systems due to the unwillingness of producers to provide reserve information as well as the cost of such evaluations. Accordingly, we do not have estimates of total reserves dedicated to our systems or the anticipated life of such reserves. If the total reserves or estimated life of the reserves connected to our pipeline systems is less than we anticipate and we are unable to secure additional sources of natural gas, then the volumes of natural gas transported on our pipelines in the future could be less than we anticipate. A decline in the volumes of natural gas transported on our pipeline systems may cause our revenues to be less than we expect which could have a material adverse effect on our business, financial condition and our ability to make cash distributions to you.

We are exposed to the credit risk of our customers and counterparties, and a general increase in the nonpayment and nonperformance by our customers could have an adverse impact on our cash flows, results of operations and financial condition.

Risks of nonpayment and nonperformance by our customers are a major concern in our business. We are subject to risks of loss resulting from nonpayment or nonperformance by our customers. Any increase in the nonpayment and nonperformance by our customers could have an adverse impact on our operating results and could adversely impact our liquidity.

Our profitability depends upon prices and market demand for natural gas and NGLs, which are beyond our control and have been volatile.

Our profitability is affected by prevailing NGL and natural gas prices, and we are subject to significant risks due to fluctuations in commodity prices. In the past, the prices of natural gas and NGLs have been extremely volatile, and we expect this volatility to continue. For example, during the year ended December 31, 2007, the Houston Ship Channel, or HSC, natural gas index price ranged from a high of $7.51 per MMBtu to a low of $5.23 per MMBtu. A composite of the Oil Price Information Service, or OPIS, Mt. Belvieu monthly average NGL price based upon our average NGL composition during the year ended December 31, 2007 ranged from a high of approximately $1.462 per gallon to a low of approximately $0.834 per gallon.

In order to calculate the sensitivity of our total segment gross margin to commodity price changes, we adjusted our operating models for actual commodity prices, plant recovery rates and volumes. We have calculated that a 1-cent per gallon change in either direction of NGL prices would have resulted in a corresponding change of approximately $1.3 million to our total segment gross margin for the year ended December 31, 2007. We also calculated that a 10-cent per MMBtu increase in the price of natural gas would have resulted in approximately a $1.2 million decrease to our total segment gross margin, and vice versa, for the year ended December 31, 2007. These relationships are not necessarily linear. Although our sensitivity analysis takes into account our hedge portfolio, it does not fully reflect the effects of our hedging program due to the prices received for natural gas and NGLs during the year ended December 31, 2007. If actual prices were to fall below the strike prices of our hedges, sensitivity to the change in commodity prices would be reduced. Additionally, if processing margins were negative, we could operate our Houston Central plant in a conditioning mode so that additional increases in natural gas prices would have a positive impact to our total segment gross margin. For a discussion of total segment gross margin, a non-GAAP financial measure, please read Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operation — Overview." For a discussion of our risk management activities and our ability to condition gas at our Houston Central plant, please read Item 7A, "Quantitative and Qualitative Disclosures about Market Risk" and Item 1, "Business — Our Segments — Texas Houston Central Systems and Our Houston Central Processing Plant," respectively.

The markets and prices for natural gas and NGLs depend upon many factors beyond our control. These factors include demand for oil, natural gas, liquefied natural gas, or LNG, nuclear energy, coal and NGLs, which fluctuate with changes in market and economic conditions and other factors, including:

- the impact of weather on the demand for oil and natural gas;
- the level of domestic oil and natural gas production;
- the availability of imported oil, natural gas, liquefied natural gas and NGLs;
- international demand for LNG, oil and NGLs;
- actions taken by foreign oil and gas producing nations;
- the availability of local, intrastate and interstate transportation systems;
- the availability and marketing of competitive fuels;
- the impact of energy conservation efforts; and
- the extent of governmental regulation and taxation.

Our hedging activities do not eliminate our exposure to fluctuations in commodity prices and interest rates and may reduce our cash flow and subject our earnings to increased volatility.

Our operations expose us to fluctuations in commodity prices. We utilize derivative financial instruments related to the future price of crude oil, natural gas and certain NGLs with the intent of reducing the volatility of our cash flows due to fluctuations in commodity prices. Specifically, we have executed (i) put options and call spread options with respect to natural gas, (ii) put options and swaps with respect to certain NGL products and (iii) put options with respect to crude oil. We also have exposure to interest rate fluctuations as a result of variable rate revolving debt under our credit agreement. We have entered into interest rate swap agreements to convert a portion of this variable rate debt to a fixed rate obligation, thereby reducing the exposure to market rate fluctuations. Please read Item 7A "Quantitative and Qualitative Disclosures about Market Risk" for a summary of our commodity and interest rate hedges at December 31, 2007.

We have entered into derivative transactions related to only a portion of our variable rate debt and of the volume of our expected natural gas and condensate supply, production of NGLs and natural gas requirements. As a result, we will continue to have direct interest rate and commodity price risk with respect to the unhedged portion. To the extent we hedge our commodity price and interest rate risk using swap instruments, we will forego the benefits we would otherwise experience if commodity prices or interest rates were to change in our favor.

Even though our hedging activities are monitored by management, these activities could reduce our cash flow in some circumstances, including if the counterparty to the hedging contract defaults on its contract obligations, if there is a change in the expected differential between the underlying price in the hedging agreement and the actual prices received or if production is less than expected. If the actual amount of production is lower than the amount that is subject to our swap instruments, we might be forced to satisfy all or a portion of our swap transactions without the benefit of the cash flow from our sale of the underlying physical commodity, resulting in a reduction of our cash flow.

The accounting standards regarding hedge accounting are rigorous. Our earnings could be subject to increased volatility to the extent our derivatives do not continue to qualify for hedge accounting. Also, to the extent we are unable to obtain, or choose not to seek hedge accounting in conjunction with any future acquisitions as a result of the type of commodity risk assumed, or structure of such acquisition, our earnings could be subject to increased volatility. In addition, it is not always possible for us to engage in a hedging transaction that completely mitigates our exposure to commodity prices. Our financial statements may reflect a gain or loss arising from an exposure to commodity prices for which we are unable to enter into a completely effective hedge.

We will continue to evaluate whether to enter into any new hedging arrangements, but there can be no assurance that we will enter into any new hedging arrangement or that our future hedging arrangements will be on terms similar to our existing hedging arrangements.

Federal, state or local regulatory measures could adversely affect our business.

Our pipeline transportation and gathering systems are subject to federal, state and/or local regulation. Most of our natural gas pipeline assets are gathering systems that are considered non-utilities in the states in which they are located. The Natural Gas Act, or NGA, leaves any economic regulation of natural gas gathering to the states. Texas, Oklahoma and Wyoming, the states in which our pipeline facilities are located, do not currently regulate gathering fees.

Our gathering fees and our terms and conditions of service may nonetheless be constrained through state anti-discrimination laws. The states in which we operate have adopted complaint-based regulation of natural gas gathering activities. Natural gas producers, shippers and other affected parties may file complaints with state regulators in an effort to resolve grievances relating to natural gas gathering access and discrimination with regard to rates and terms of service. A successful complaint, or new laws or regulatory rulings related to gathering, could increase our costs or require us to alter our gathering charges, and our business, and therefore, results of operations and financial condition could be adversely affected. Other state laws and regulations may not directly regulate our business, but may nonetheless affect the availability of natural gas for gathering, purchase, processing and sale, including state regulation of production rates and maximum daily production allowables from gas wells.

Some of our intrastate natural gas transmission pipelines are subject to regulation as gas utilities by the Texas Railroad Commission, or TRRC. The TRRC's jurisdiction over these pipelines extends to both rates and pipeline safety. The rates we charge for transportation services in Texas are deemed just and reasonable under Texas law unless challenged in a complaint. A successful complaint, or new state laws or regulatory rulings related to intrastate transmission, could increase our costs or require us to alter our service charges, and our business, results of operations and financial condition could be adversely affected.

To the extent that our intrastate pipelines transport natural gas in interstate commerce, the rates, terms and conditions of that transportation service are subject to regulation by the FERC pursuant to Section 311 of the Natural Gas Policy Act of 1978, or NGPA. Section 311 requires, among other things, that rates for such interstate service, which may be established by the FERC or the applicable state agency, be "fair and equitable" and permits the FERC to approve terms and conditions of service. If our Section 311 rates are successfully challenged, if we are unable to include all of our costs in the cost of service approved in a future rate case, if FERC changes its regulations or policies, or establishes more onerous terms and conditions applicable to Section 311 service, this may adversely affect our business. Any reduction in our rates could have an adverse effect on our business, results of operations and financial condition. Should we fail to comply with all applicable FERC-administered statutes, rules, regulations and orders, we could be subject to substantial penalties and fines.

The price at which we buy and sell natural gas, NGLs and crude oil is currently not subject to federal regulation and, for the most part, is not subject to state regulation. However, with regard to our physical purchases and sales of these energy commodities, our gathering or transportation of these energy commodities, and any related hedging activities that we undertake, we are required to observe anti-market manipulation laws and related regulations enforced by the FERC and/or the Commodity Futures Trading Commission, or the CFTC. The FERC and CFTC hold substantial enforcement authority under the anti-market manipulation laws and regulations, including the ability to assess civil penalties of up to $1 million per day per violation, to order disgorgement of profits and to recommend criminal penalties. Should we violate the anti-market manipulation laws and regulations, we could also be subject to related third party damage claims by, among others, sellers, royalty owners and taxing authorities.

The FERC has also promulgated additional market-monitoring and reporting regulations intended to increase the transparency of wholesale energy markets, protect the integrity of such markets, and improve the FERC's ability to assess market forces and detect market manipulation.

These and other new laws and regulations or any administrative or judicial re-interpretations of existing laws, regulations or agreements could require us to incur increased costs and administrative burdens, and our business, results of operations and financial condition could be adversely affected. For instance, on February 19, 2008, the U.S. Supreme Court agreed to hear arguments in a lawsuit, *Montana v. Wyoming*, filed by the State of Montana against Wyoming over water rights in two rivers that flow through both states. Montana is asserting that Wyoming is using too much water from the Tongue and Powder Rivers pursuant to the Yellowstone River Compact, an agreement that both states entered into in 1950 addressing how the states may share water from the Yellowstone River and its tributaries, including the Tongue and Powder Rivers. A critical element of Montana's argument is that the Compact applies to groundwater and, among other things, that Wyoming's permitting of coal bed methane production, which involves the pumping of large quantities of groundwater, is depleting the waters of the two rivers to the detriment of Montana and its water users and in violation of the Compact. Wyoming's position is that the Compact does not address groundwater. Among other things, Montana asks the High Court to declare the rights of Montana to water from these two rivers pursuant to the Compact and to issue a decree commanding Wyoming in the future to deliver the waters of these two rivers to Montana in accord with the Compact. This lawsuit has only recently been accepted for review by the U.S. Supreme Court and no substantive determination has yet been made regarding the use of waters from these two rivers, including the associated groundwater. Any decision made by the U.S. Supreme Court as a result of this case that effectively limits the amount of groundwater pumped in connection with coal bed methane production in Wyoming may have significant adverse impacts on the volume of production by coal bed methane producers in affected areas of Wyoming and, correspondingly, on gathering services that Bighorn and Fort Union provide.

For additional information on the federal, state and local regulations affecting our business, please read the subsections under Item 1 captioned "Business — Regulation" and "— Environmental Matters."

A change in the characterization of some of our assets by federal, state or local regulatory agencies could adversely affect our business.

Section 1(b) of the NGA provides that the FERC's jurisdiction does not extend to facilities used for the production or gathering of natural gas. "Gathering" is not specifically defined by the NGA or its implementing regulations, and there is no bright-line test for determining the jurisdictional status of pipeline facilities. Although some guidance is provided by case law, the process of determining whether facilities constitute gathering facilities for purposes of regulation under the NGA is fact-specific and subject to regulatory change. Additionally, our construction, expansion, extension or alteration of pipeline facilities may involve regulatory, environmental, political and legal uncertainties, including the possibility that physical changes to our pipeline systems may be deemed to affect their jurisdictional status.

The distinction between FERC-regulated natural gas transmission services and federally unregulated gathering services has been the subject of regular litigation, as has been the line between intrastate and interstate transportation services. Thus, the classification and regulation of some of our natural gas gathering facilities and intrastate transportation pipelines may be subject to change based on future determinations by the FERC and/or the courts. Should any of our natural gas gathering or intrastate facilities be deemed to be jurisdictional under the NGA, we could be required to comply with numerous federal requirements for interstate service, including laws and regulations governing the rates charged for interstate transportation services, the terms and conditions of service, certification and construction of new facilities, the extension or abandonment of services and facilities, the maintenance of accounts and records, the initiation and discontinuation of services, the monitoring and posting of real-time system information and many other requirements. Failure to comply with all applicable FERC-administered statutes, rules, regulations and orders could result in substantial penalties and fines. It is also possible that our gathering facilities could be deemed by a relevant state commission or court, or by a change in law or regulation, to constitute intrastate pipeline subject to general state law and regulation of rates and terms and conditions of service. A change in jurisdictional status through litigation or legislation could require significant changes to the rates, terms and conditions of service on the affected pipeline, could increase the expense of providing service and adversely affect our business.

The distinction between FERC-regulated common carriage of crude oil and NGLs, and the non-jurisdictional intrastate transportation of those energy commodities, has also been the subject of litigation. The FERC, under the ICA, the Energy Policy Act of 1992, and rules and orders promulgated thereunder, regulates the tariff rates for interstate crude oil and NGL transportation and these rates must be filed with the FERC. Under the ICA, tariffs must be just and reasonable and not unduly discriminatory or confer any undue preference. To the extent any of our NGL or crude oil assets are subject to the jurisdiction of FERC, the FERC's rate-making methodologies could limit our ability to set rates that we might otherwise be able to charge, could delay the use of rates that reflect increased costs, and could subject us to potentially burdensome and expensive operational, reporting and other requirements. Any of the foregoing could adversely affect our business, revenues and cash flow. For additional information concerning FERC and other regulatory agencies relating to our business, please read "Business — Regulation."

We may incur significant costs and liabilities resulting from pipeline integrity programs and related repairs.

We are subject to the Natural Gas Pipeline Safety Act of 1968, or NGPSA, and the Pipeline Safety Improvement Act of 2002. The NGPSA regulates safety requirements in the design, construction, operation and maintenance of gas pipeline facilities while the Pipeline Safety Improvement Act establishes mandatory inspections for all United States oil and natural gas transportation pipelines and gathering lines meeting certain operational risk and location requirements. The DOT has developed regulations implementing the Pipeline Safety Improvement Act that require pipeline operators to implement integrity management programs, including more frequent inspections and other safety protections in areas where the consequences of potential pipeline accidents pose the greatest risk to people and their property.

Although many of our natural gas facilities fall within a class that is not subject to these requirements, we may incur significant costs and liabilities associated with repair, remediation, preventative or mitigation measures associated with non-exempt pipeline. Such costs and liabilities might relate to repair, remediation, preventative or mitigating actions that may be determined to be necessary as a result of the testing program, as well as lost cash flows resulting from shutting down our pipelines during the pendency of such repairs. Additionally, we may be affected by the testing, maintenance and repair of pipeline facilities downstream from our own facilities. Our NGL pipelines are also subject to integrity management and other safety regulations imposed by the TRRC.

Any regulatory expansion of the existing pipeline safety requirements or the adoption of new pipeline safety requirements could also increase our cost of operation and impair our ability to provide service during the period in which assessments and repairs take place, adversely affecting our business.

Because we handle natural gas, crude oil and other petroleum products in our pipeline and processing businesses, we may incur significant costs and liabilities in the future resulting from a failure to comply with new or existing environmental regulations or an accidental release of hazardous substances into the environment.

The operation of our gathering systems, plants and other facilities is subject to stringent and complex federal, state and local environmental laws and regulations. These laws and regulations can restrict or impact our business activities in many ways, including restricting the manner in which we dispose of wastes and other regulated substances, requiring remedial action to remove or mitigate contamination, and requiring capital expenditures to comply with control requirements. Failure to comply with these laws and regulations may trigger a variety of administrative, civil and criminal enforcement measures, including the assessment of monetary penalties, the imposition of remedial requirements and the issuance of orders enjoining future operations. Certain environmental statutes impose strict, joint and several liability for costs required to clean up and restore sites where substances and wastes have been disposed or otherwise released. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of substances or wastes into the environment.

There is inherent risk of the incurrence of environmental costs and liabilities in our business due to our handling of natural gas, crude oil and other petroleum products, air emissions related to our operations, historical industry operations including releases of substances into the environment and waste disposal practices. For example, an accidental release from one of our pipelines or processing facilities could subject us to substantial liabilities arising from environmental cleanup, restoration costs and natural resource damages, claims made by neighboring landowners and other third parties for personal injury and property damage and fines or penalties for related violations of environmental laws or regulations. Moreover, the possibility exists that stricter laws, regulations or enforcement policies could significantly increase our compliance costs and the cost of any remediation that may become necessary. We may not be able to recover some or any of these costs from insurance. Please read "Business — Environmental Matters."

Expanding our business by constructing new assets will subject us to risks that projects may not be completed on schedule, the costs associated with the projects may exceed our expectations and additional natural gas supplies may not be available following completion of the projects, which could cause our revenues to be less than anticipated. Our operating cash flows from our capital projects may not be immediate.

One of the ways we may grow our business is through the construction of additions to our existing gathering and transportation systems (including additional compression) and modifications to, or construction of, natural gas processing plants. The construction of additions or modifications to our existing gathering and transportation systems and processing and treating facilities, and the construction of new gathering and processing facilities, involve numerous regulatory, environmental, political, legal and operational uncertainties beyond our control and require the expenditure of significant amounts of capital. These projects also involve numerous economic uncertainties including the impact of inflation on project costs and the availability of required resources. If we undertake these projects, they may not be completed on schedule or at all or at the budgeted cost. Moreover, we may not receive any material increase in operating cash flow from a project for some time. If we experience unanticipated or extended delays in generating operating cash flow from these projects, then we may need to reduce or reprioritize our capital budget in order to meet our capital requirements. We may also rely on estimates of future production in our decision to construct additions to our gathering and transportation systems, which may prove to be inaccurate because of the numerous uncertainties inherent in estimating quantities of future production. As a result, new facilities may not be able to attract enough throughput to achieve our expected investment return and that, in turn, could adversely affect our cash flows and results of operations.

If the cost of renewing existing rights-of-way increases, it may have an adverse impact on our profitability. In addition, if we are unable to obtain new rights-of-way, then we may be unable to fully execute our growth strategy.

The construction of additions to our existing gathering and transportation assets may require us to obtain new rights-of-way prior to constructing new pipelines. We may be unable to obtain such rights-of-way to connect new natural gas supplies to our existing gathering lines or capitalize on other attractive expansion opportunities. Additionally, it may become more expensive for us to obtain new rights-of-way or to renew existing rights-of-way. If the cost of renewing existing rights-of-way increases, then our results of operations could be adversely affected. In addition, increased rights-of-way costs could impair our ability to grow.

Our business involves many hazards and operational risks, some of which may not be fully covered by insurance. If a significant accident or event occurs that is not fully insured, our operations could be temporarily or permanently impaired, and our liabilities and expenses could be significant.

Our operations are subject to the many hazards inherent in the gathering, compression, treating, processing and transportation of natural gas and NGLs, including:

- damage to pipelines, pipeline blockages and damage to related equipment and surrounding properties caused by hurricanes, tornadoes, floods, fires, extreme weather conditions and other natural disasters and acts of terrorism;
- inadvertent damage from motor vehicles, construction or farm equipment;
- leaks of natural gas, NGLs and other hydrocarbons;
- operator error; and
- fires and explosions.

These risks could result in substantial losses due to personal injury and/or loss of life, severe damage to and destruction of property and equipment and pollution or other environmental damage and may result in curtailment or suspension of our related operations. In addition, mechanical malfunctions, undetected ruptures in pipelines, faulty measurement or other errors may result in significant costs or lost revenues. Our operations are primarily concentrated in the Texas Gulf Coast and north Texas regions, in central and eastern Oklahoma and in Wyoming, and a natural disaster or other hazard affecting any of these areas could have a material adverse effect on our operations. For example, although we did not suffer significant damage, Hurricane Katrina and Hurricane Rita damaged gathering systems, processing facilities and NGL fractionators along the Gulf Coast in August and September 2005, respectively, which curtailed or suspended the operations of various energy companies with assets in the region. There can be no assurance that insurance will cover all damages and losses resulting from these types of natural disasters. We are not fully insured against all risks incident to our business. In accordance with typical industry practice, we generally do not have any property insurance on any of our underground pipeline systems that would cover damage to the pipelines. We are not insured against all environmental accidents that might occur, other than those considered to be sudden and accidental. Our business interruption insurance covers only certain lost revenues arising from physical damage to our processing plants and certain pipeline facilities. If a significant accident or event occurs that is not fully insured, our operations could be temporarily or permanently impaired, and our liabilities and expenses could be significant.

Due to our limited asset diversification, adverse developments in our gathering, transportation, processing and related businesses would have a significant impact on our results of operations.

Substantially all of our revenues are generated from our gathering, dehydration, treating, conditioning, processing and transportation businesses, and as a result, our financial condition depends upon prices of, and continued demand for, natural gas and NGLs. Furthermore, substantially all of our assets are located in Texas, Oklahoma and Wyoming. Due to our limited diversification in asset type and location, an adverse development in one of these businesses or in these areas would have a significantly greater impact on our cash flows, results of operations and financial condition than if we maintained more diverse assets.

If we fail to maintain an effective system of internal control over financial reporting, we may not be able to accurately report our financial results or prevent fraud. As a result, we may experience materially higher compliance costs.

In early 2005, we began a process to annually document and evaluate our internal control over financial reporting in order to satisfy the requirements of Section 404 of the Sarbanes-Oxley Act of 2002 and the related regulations, which require annual management assessments of the effectiveness of our internal control over financial reporting and a report by our independent registered public accounting firm addressing these assessments. In this regard, management has dedicated internal resources, engaged outside consultants and adopted a detailed work plan to (i) assess and document the adequacy of our internal control over financial reporting, (ii) take steps to improve control processes, where appropriate, (iii) validate through testing that controls are functioning as documented and (iv) implement a continuous review and reporting process for internal control over financial reporting. Our efforts to comply with Section 404 of the Sarbanes-Oxley Act of 2002 and the related regulations regarding our assessment of our internal control over financial reporting and our independent registered public accounting firm's audit of that assessment have resulted, and are likely to continue to result, in increased expenses. We cannot be certain that these measures will ensure that we maintain adequate controls over our financial processes and reporting in the future. Any failure to implement required new controls, or difficulties encountered in their implementation, could harm our operating results or cause us to fail to meet our reporting obligations. If compliance with policies or procedures deteriorate and we fail to correct any associated issues in the design or operating effectiveness of our internal control over financial reporting or fail to prevent fraud, current and potential holders of our securities could lose confidence in our financial reporting, which could harm our business.

We own interests in limited liability companies and a general partnership in which third parties also own interests, which may limit our ability to influence significant business decisions affecting these entities.

In addition to our wholly owned subsidiaries, we own interests in a number of entities in which third parties also own an interest. These interests include our:

- 62.5% interest in Webb/Duval Gatherers;
- majority interest in Southern Dome, LLC;
- 51% interest in Bighorn Gas Gathering, L.L.C.; and
- 37.04% interest in Fort Union Gas Gathering, L.L.C.

Although we serve as operator of Webb/Duval Gatherers, managing member and operator of Southern Dome, managing member and field operator of Bighorn and managing member of Fort Union, certain substantive business decisions with respect to these entities require the majority or unanimous approval of the owners or, in the case of Bighorn, of a management committee to which we have the right to appoint 50% of the members. Examples of some of these substantive business decisions include significant expenditures or contractual commitments, the construction or acquisition of assets, borrowing money or otherwise raising capital and transactions not in the ordinary course of business, among others. Differences in views among the respective owners of these entities could result in delayed decisions or in failures to agree on significant matters, potentially adversely affecting their respective businesses and results of operations or prospects and, in turn, the amounts and timing of cash from operations distributed to their respective members or partners, including us.

In addition, we do not control the day-to-day operations of Fort Union. Our lack of control over Fort Union's day-to-day operations and the associated costs of operations could result in our receiving lower cash distributions than we anticipate, which could reduce our cash flow available for distribution to our unitholders.

Risks Related to Our Structure

Our limited liability company agreement prohibits a unitholder who acquires 15% or more of our common units without the approval of our Board of Directors from engaging in a business combination with us for three years. This provision could discourage a change of control that our unitholders may favor, which could negatively affect the price of our common units.

Our limited liability company agreement effectively adopts Section 203 of the Delaware General Corporation Laws, or the DGCL. Section 203 of the DGCL as it applies to us prevents an interested unitholder, defined as a person who owns 15% or more of our outstanding units, from engaging in business combinations with us for three years following the time such person becomes an interested unitholder. Section 203 broadly defines "business combination" to encompass a wide variety of transactions with or caused by an interested unitholder, including mergers, asset sales and other transactions in which the interested unitholder receives a benefit on other than a pro rata basis with other unitholders. This provision of our limited liability company agreement could have an anti-takeover effect with respect to transactions not approved in advance by our Board of Directors, including discouraging takeover attempts that might result in a premium over the market price for our common units.

Our cap on certain general and administrative expenses expired on December 31, 2007, and our pre-IPO investors are no longer required to reimburse us for certain amounts in excess of the cap, which could materially reduce the cash available for distribution to our unitholders.

Pursuant to our limited liability company agreement, our pre-IPO investors agreed to reimburse us for the general and administrative expenses we incurred for the years 2005 through 2007 in excess of levels set forth in our limited liability company agreement (subject to certain limitations). In satisfaction of this obligation, our pre-IPO investors made capital contributions to us of \$4.1 million, \$4.6 million, \$10.0 million and \$3.9 million in 2005, 2006, 2007 and 2008, respectively. Commencing with the first quarter of 2008, our pre-IPO investors no longer have this reimbursement obligation. As a result, all of our general and administrative expenses will be paid by us, which could materially reduce the cash available for distributions to our unitholders.

We may issue additional common units without your approval, which would dilute your existing ownership interests.

We may issue an unlimited number of limited liability company interests of any type, including common units, without the approval of our unitholders. Our limited liability company agreement does not give the unitholders the right to approve our issuance at any time of equity securities ranking junior to the common units.

The issuance of additional common units or other equity securities of equal or senior rank will have the following effects:

- your proportionate ownership interest in us will decrease;
- the amount of cash available for distribution on each unit may decrease;
- the relative voting strength of each previously outstanding unit will be diminished; and
- the market price of the common units may decline.

Our limited liability company agreement provides for a limited call right that may require you to sell your common units at an undesirable time or price.

If, at any time, any person owns more than 90% of the common units then outstanding, such person has the right, but not the obligation, which it may assign to any of its affiliates or to us, to acquire all, but not less than all, of the remaining common units then outstanding at a price not less than the then-current market price of the common units. As a result, you may be required to sell your common units at an undesirable time or price and may therefore not receive any return on your investment. You may also incur tax liability upon a sale of your units.

Certain of our investors may sell units in the public market, which could reduce the market price of our outstanding common units.

Pursuant to agreements with our pre-IPO investors and investors in private placements effected in 2005, 2006 and 2007, we have filed or agreed to file registration statements on Form S-3 registering sales by selling unitholders of an aggregate of 39,354,334 of our common units (as adjusted to reflect the March 30, 2007 two-for-one split of all of our outstanding common units), including:

- 1,184,557 common units to be issued upon conversion of Class C units we issued to the sellers in the Cimmarron acquisition;
- 3,245,817 common units to be issued upon conversion of Class D units we issued to the sellers in the Cantera acquisition; and
- 5,598,836 common units to be issued upon conversion of Class E units issued in our October 19, 2007 private placement.

While investors have routinely sold common units registered under our effective registration statements, a significant number of common units remains unsold pursuant to these registration statements. If investors holding these units were to dispose of a substantial portion of these units in the public market, whether in a single transaction or series of transactions, it could temporarily reduce the market price of our outstanding common units. In addition, these sales, or the possibility that these sales may occur, could make it more difficult for us to sell our common units in the future.

Tax Risks to Common Unitholders

Our tax treatment depends on our status as a partnership for federal income tax purposes, as well as our not being subject to a material amount of entity-level taxation by individual states. If the IRS were to treat us as a corporation for tax purposes or we were to become subject to a material amount of entity-level taxation, it would substantially reduce the amount of cash available for distribution to our unitholders.

The anticipated after-tax economic benefit of an investment in our common units depends largely on our being treated as a partnership for federal income tax purposes. We have not requested, and do not plan to request, a ruling from the IRS on this or any other tax matter affecting us.

Despite the fact that we are a limited liability company under Delaware law, it is possible in certain circumstances for a limited liability company such as ours to be treated as a corporation for federal income tax purposes. Although we do not believe based upon our current operations that we should be so treated, a change in our business (or a change in current law) could cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to taxation as an entity.

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rates, currently at a maximum rate of 35%, and would likely pay state income tax at varying rates. Distributions to you would generally be taxed again as corporate distributions, and no income, gain, loss or deduction would flow through to you. Because a tax would be imposed on us as a corporation, our cash available for distribution to our unitholders would be substantially reduced. Therefore, treatment of us as a corporation would result in a material reduction in the anticipated cash flow and after-tax return to our unitholders and therefore would likely result in a substantial reduction in the value of our common units.

Current law or our business may change so as to cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to entity-level taxation. In addition, because of widespread state budget deficits and other reasons, several states are evaluating ways to subject partnerships and limited liability companies to entity-level taxation through the imposition of state income, franchise or other forms of taxation. For example, we were subject to a new entity level tax on the portion of our income that is generated in Texas beginning in our tax year ending December 31, 2007. Specifically, the Texas margin tax is imposed at a maximum effective rate of 0.7% of our federal gross income apportioned to Texas. Imposition of such a tax on us by Texas, or any other state, will reduce the cash available for distribution to our unitholders. Moreover, at the federal level, legislation has been proposed that would eliminate pass-through tax treatment for certain publicly traded limited liability companies. Although such legislation would not apply to us as currently proposed, it could be amended prior to enactment in a manner that does apply to us. We are unable to predict whether any of these changes or other proposals will ultimately be enacted. Additionally, any modification to the federal income tax laws and interpretations thereof may or may not be applied retroactively. Any such changes could negatively impact the value of an investment in our common units.

Our limited liability company agreement provides that if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for federal, state or local income tax purposes, then the minimum quarterly distribution amount will be adjusted to reflect the impact of that law on us.

If the IRS contests the federal income tax positions we take, the market for our common units may be adversely impacted, and the costs of any IRS contest will reduce cash available for distribution to our unitholders.

We have not requested a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes or any other matter affecting us. The IRS may adopt positions that differ from the conclusions of our counsel or from the positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of our counsel's conclusions or the positions we take. A court may disagree with some or all of our counsel's conclusions or the positions we take. Any contest with the IRS may materially and adversely impact the market for our common units and the price at which they trade. In addition, our costs of any contest with the IRS will be borne indirectly by our unitholders because the costs will reduce our cash available for distribution.

A unitholder will be required to pay taxes on the share of our income allocated to you even if you do not receive any cash distributions from us.

Because our unitholders are treated as partners to whom we allocate taxable income, you will be required to pay any federal income taxes and, in some cases, state and local income taxes on your share of our taxable income, regardless of the amount of any distributions from us. You may not receive cash distributions from us equal to your share of our taxable income or even equal to the actual tax liability that results from that income.

Tax gain or loss on disposition of our common units could be more or less than expected.

If you sell your common units, you will recognize a gain or loss equal to the difference between the amount realized and your tax basis in those common units. Because distributions in excess of your allocable share of our net taxable income decrease your tax basis in your common units, the amount, if any, of such prior excess distributions with respect to the units you sell, will, in effect, become taxable income to you if you sell such units at a price greater than your tax basis, even if the price you receive is less than your original cost. Furthermore, a substantial portion of the amount realized, whether or not representing gain, may be taxed as ordinary income due to potential recapture items, including depreciation recapture. In addition, because the amount realized includes a unitholder's share of our nonrecourse liabilities, if you sell your units, you may incur a tax liability in excess of the amount of cash you receive from the sale.

Tax-exempt entities and foreign persons face unique tax issues from owning common units that may result in adverse tax consequences to them.

Investment in common units by tax-exempt entities, including employee benefit plans and individual retirement accounts (known as IRAs), and non-U.S. persons raises issues unique to them. For example, virtually all of our income allocated to organizations exempt from federal income tax, including individual retirement accounts and other retirement plans, will be unrelated business taxable income and will be taxable to such a unitholder. Distributions to non-U.S. persons will be reduced by withholding taxes at the highest applicable tax rate, and non-U.S. persons will be required to file United States federal tax returns and pay tax on their share of our taxable income. If you are a tax-exempt entity or a non-U.S. person, you should consult your tax advisor before investing in our units.

We treat each purchaser of our common units as having the same tax benefits without regard to the actual common units purchased. The IRS may challenge this treatment, which could adversely affect the value of the common units.

Because we cannot match transferors and transferees of common units and for certain other reasons, we have adopted depreciation and amortization positions that may not conform with all aspects of existing Treasury Regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to our unitholders. It also could affect the timing of these tax benefits or the amount of gain on the sale of common units and could have a negative impact on the value of our common units or result in audits of and adjustments to our unitholders' tax returns.

The sale or exchange of 50% or more of our capital and profits interests during any twelve-month period will result in the technical termination of our partnership for federal income tax purposes.

We will be considered to have technically terminated for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. While we would continue our existence as a Delaware limited liability company, our technical termination would, among other things result in the closing of our taxable year for all unitholders, which would result in us filing two tax returns (and our unitholders could receive two Schedules K-1) for one fiscal year and could result in a deferral of depreciation deductions allowable in computing our taxable income. In the case of a unitholder reporting on a taxable year other than a fiscal year ending December 31, the closing of our taxable year may also result in more than twelve months of our taxable income or loss being includable in his taxable income for the year of termination. A technical termination would not affect our classification as a partnership for federal income tax purposes, but instead, we would be treated as a new partnership for tax purposes. If treated as a new partnership, we must make new tax elections and could be subject to penalties if we are unable to determine that a termination occurred.

As a result of investing in our common units, you may be subject to state and local taxes and return filing requirements in states where you do not live.

In addition to federal income taxes, unitholders will likely be subject to other taxes, including state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we do business or own property now or in the future, even if our unitholders do not reside in any of those jurisdictions. Our unitholders will likely be required to file state and local income tax returns and pay state and local income taxes in some or all of these jurisdictions. Further, unitholders may be subject to penalties for failure to comply with those requirements. We currently do business and own assets in Texas, Oklahoma, Wyoming and Louisiana. Although Texas and Wyoming do not currently impose a personal income tax, Oklahoma and Louisiana do and as we make acquisitions or expand our business, we may do business or own assets in other jurisdictions that impose a personal income tax. It is the responsibility of each unitholder to file all United States federal, state and local tax returns that may be required of such unitholder. Our counsel has not rendered an opinion on the state or local tax consequences of an investment in the common units.

Item 1B. *Unresolved Staff Comments*

None.

Item 2. *Properties*

A description of our properties is contained in Item 1 "Business" of this Annual Report. Substantially all of our pipelines are constructed under rights-of-way granted by the apparent record landowners. Lands over which pipeline rights-of-way have been obtained may be subject to prior liens that have not been subordinated to the right-of-way grants. We have obtained, where necessary, license or permit agreements from public authorities and railroad companies to cross over or under, or to lay facilities in or along, waterways, county roads, municipal streets, railroad properties and state highways, as applicable. In some cases, property on which our pipeline was built was purchased in fee.

Some of our leases, easements, rights-of-way, permits, licenses and franchise ordinances require the consent of the current landowner to transfer these rights, which in some instances is a governmental entity. We believe that we have obtained sufficient third-party consents, permits and authorizations for the transfer of the assets necessary for us to operate our business in all material respects. With respect to any consents, permits or authorizations that have not been obtained, we believe that the failure to obtain these consents, permits or authorizations will have no material adverse effect on the operation of our business.

We believe that we have satisfactory title to our assets. Title to property may be subject to encumbrances. We believe that none of these encumbrances will materially detract from the value of our properties or from our interest in these properties nor will they materially interfere with their use in the operation of our business.

Item 3. *Legal Proceedings*

Although we may, from time-to-time, be involved in litigation and claims arising out of our operations in the ordinary course of business, we are not currently a party to any material legal proceedings, except for proceedings described below, which we have determined not to be material to us because we are fully indemnified. In addition, we are not aware of any material legal or governmental proceedings against us, or contemplated to be brought against us, under the various environmental protection statutes to which we are subject.

As a result of our acquisition of Cantera in October 2007, we became a party to a number of legal proceedings alleging (i) false reporting of natural gas prices by CMS Field Services, Inc. ("CMSFS") and numerous other parties and (ii) other related claims. The claims made in these proceedings are based on events that occurred prior to the acquisition of CMSFS by Cantera Resources, Inc. in June 2003 (the "CMS Acquisition"). Pursuant to the acquisition agreement executed in connection with the CMS Acquisition, CMS Gas Transmission Company ("CMS") has assumed responsibility for the defense of these claims, and we are fully indemnified by CMS against any losses that we may suffer as a result of these claims.

Item 4. *Submission of Matters to a Vote of Security Holders*

None.

PART II

Item 5. *Market for Registrant's Common Equity, Related Unitholder Matters and Issuer Purchases of Equity Securities*

Our common units representing limited liability company interests in us are listed on The NASDAQ Stock Market LLC, or NASDAQ, under the symbol "CPNO." On February 15, 2008, the closing market price for our common units was $35.10 per unit, and there were approximately 72 common unitholders of record. Effective February 14, 2007, our 3,519,126 subordinated units (7,038,252 on a post-split basis) converted to common units on a one-for-one basis as a result of the satisfaction of the financial tests required for conversion of the subordinated units into common units, as set forth in our limited liability company agreement. Prior to conversion of the subordinated units, there was no established public trading market for our subordinated units.

There is no established public trading market for our Class C units, our Class D units or our Class E units. On February 15, 2008, there were approximately 18 Class C unitholders of record, one Class D unitholder of record and 19 Class E unitholders of record.

On February 15, 2007, our Board of Directors approved a two-for-one unit split of our outstanding units, which entitled each unitholder of record at the close of business on March 15, 2007, to receive one additional common unit for every common unit held on that date.

The following table shows the high and low sales prices per common unit, as reported by NASDAQ, for the periods indicated (as adjusted to reflect the two-for-one split of all of our common units outstanding on March 15, 2007):

	Price of Common Units		Cash Distribution per Common Unit
	High	Low	
2007:			
Quarter Ended December 31	$39.75	$33.53	$0.5100
Quarter Ended September 30(1)	$44.81	$33.25	$0.4700
Quarter Ended June 30	$45.03	$33.92	$0.4400
Quarter Ended March 31	$35.10	$28.85	$0.4200
2006:			
Quarter Ended December 31	$31.67	$26.38	$0.4000
Quarter Ended September 30	$27.40	$23.37	$0.3750
Quarter Ended June 30	$24.88	$21.64	$0.3375
Quarter Ended March 31	$22.48	$19.05	$0.3000

(1) Pursuant to the agreement among us and the accredited investors in our October 2007 private placement, common units we issued in the private placement were not eligible to receive distributions for the quarter ended September 30, 2007.

Within 45 days after the end of each quarter, we intend to pay quarterly distributions (in February, May, August and November of each year) to the extent we have sufficient available cash from operating surplus, as defined in our limited liability company agreement, no less than the minimum quarterly distribution, or MQD of $0.20 per unit ($0.80 on an annual basis), to our common unitholders of record on the applicable record date.

In the event we do not have sufficient cash to pay our distributions as well as satisfy our other operational and financial obligations, our Board of Directors has the ability to reduce or eliminate the distribution paid on our common units so that we may satisfy such obligations, including payments on our debt instruments.

Our available cash consists generally of all cash on hand at the end of the fiscal quarter, less retained cash reserves that our Board of Directors determines are necessary to (i) provide for the proper conduct of our business; (ii) comply with applicable law, any of our debt instruments, or other agreements; or (iii) provide funds for distributions to our unitholders for any one or more of the next four quarters; plus all cash on hand for the quarter resulting from eligible working capital borrowings made after the end of the quarter on the date of determination of available cash. Operating surplus generally consists of cash on hand at the closing of our IPO, cash generated from operations after deducting related expenditures and other items, plus eligible working capital borrowings after the end of the quarter, plus $12.0 million, as adjusted for reserves. Our current credit facility does not provide for working capital borrowings that would be eligible for inclusion in available cash or operating surplus.

Our Board of Directors has broad discretion to establish cash reserves that it determines are necessary or appropriate to properly conduct our business. These can include cash reserves for future capital and maintenance expenditures, reserves to stabilize distributions of cash to the unitholders, reserves to reduce debt or, as necessary, reserves to comply with the terms of any of our agreements or obligations.

Distributions

Common Units

The following table sets forth information regarding distributions to our common unitholders (in thousands except for per unit numbers):

Quarter Ending[(a)]	Distribution Per Unit	Date Declared	Record Date	Payment Date	Amount
March 31, 2006	$0.3000	April 18, 2006	May 1, 2006	May 15, 2006	$11,000
June 30, 2006	$0.3375	July 19, 2006	August 1, 2006	August 14, 2006	$12,400
September 30, 2006	$0.3750	October 18, 2006	November 1, 2006	November 14, 2006	$13,800
December 31, 2006	$0.4000	January 18, 2007	February 1, 2007	February 14, 2007	$17,025
March 31, 2007	$0.4200	April 18, 2007	May 1, 2007	May 15, 2007	$17,881
June 30, 2007	$0.4400	July 18, 2007	August 1, 2007	August 14, 2007	$18,743
September 30, 2007[(b)]	$0.4700	October 17, 2007	November 1, 2007	November 14, 2007	$20,276
December 31, 2007	$0.5100	January 16, 2008	February 1, 2008	February 14, 2008	$24,336

(a) Before February 14, 2007, the date on which our 3,519,126 subordinated units (7,038,252 on a post-split basis) converted into common units, we paid cash distributions on all common and subordinated units then outstanding.

(b) Pursuant to the agreement among us and the accredited investors in our October 2007 private placement, common units we issued in the private placement were not eligible to receive distributions for the quarter ended September 30, 2007.

The amount of available cash from operating surplus needed to pay the current distribution of $0.51 per unit, or $2.04 per unit annualized, to our common unitholders is as follows (in thousands):

	One Quarter	Four Quarters
Common units[(1)]	$24,336	$97,342

(1) Includes restricted common units and phantom units issued under our Long-Term Incentive Plan, or LTIP. Distributions made on restricted units and phantom units issued to date are subject to the same vesting provisions as the restricted units and phantom units. As of February 1, 2008, we had 241,181 outstanding restricted units and 106,545 outstanding phantom units. Annual distributions related to these restricted units and phantom units are approximately $0.7 million.

In February 2007, our Board of Directors confirmed that the financial tests required for conversion of all our outstanding subordinated units into common units had been satisfied. Accordingly, our 3,519,126 subordinated units (7,038,252 on a post-split basis) converted on a one-for-one basis into common units effective February 14, 2007, the payment date for our fourth quarter 2006 distribution to unitholders. The conversion of the subordinated units did not impact the amount of cash distributions paid by us or the total number of our outstanding units.

Class C Units

Our limited liability agreement provides that up to 25% of the total Class C units we issued in connection with the Cimmarron acquisition (less any Class C units released to us in satisfaction of certain indemnity obligations of the Cimmarron sellers) will convert into common units on each of May 1 and November 1, 2008 and May 1, 2009. Class C units are not entitled to receive quarterly cash distributions. On November 1, 2007, 394,852 of the Class C units, or 25% of the total Class C units issued, converted to common units.

Class D Units

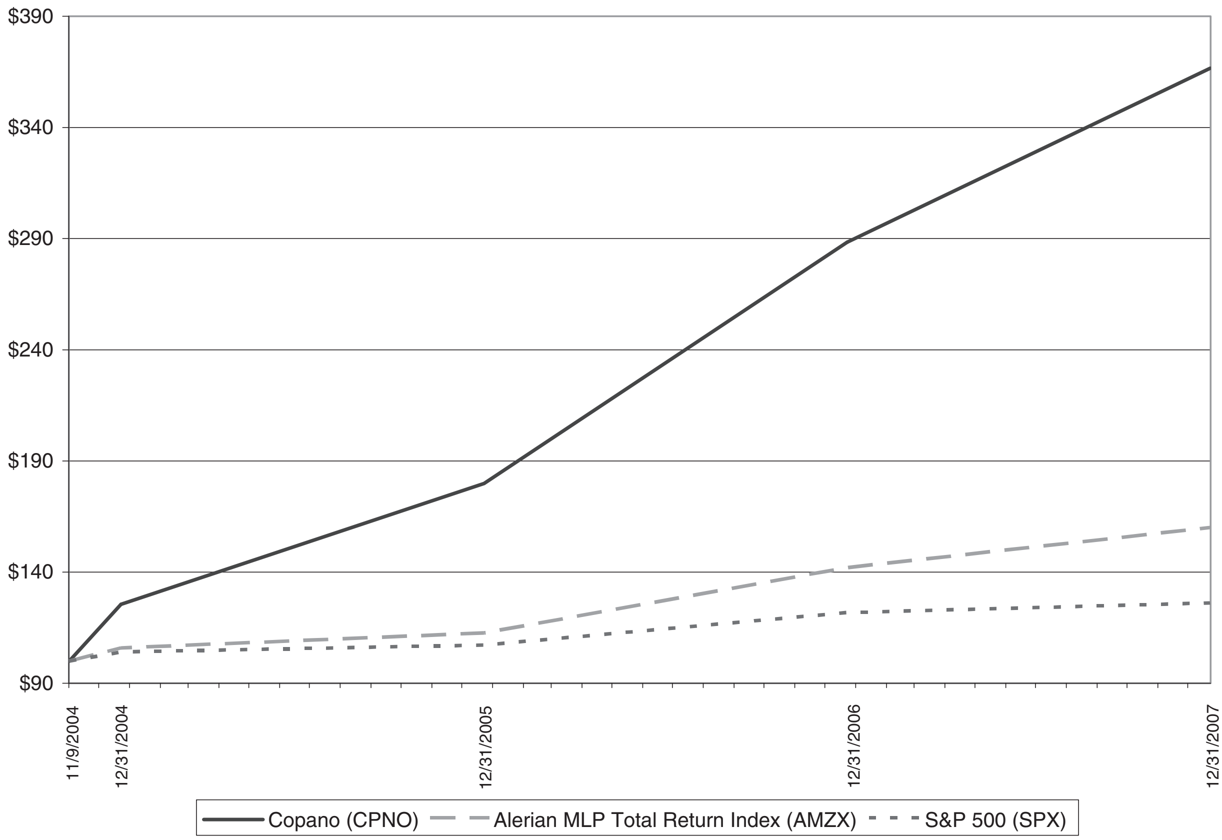
Our Class D units, which we issued to the Cantera sellers as part of the consideration for the Cantera acquisition, are convertible into our common units on a one-for-one basis upon the earlier of (a) payment of our common unit distribution with respect to the fourth quarter of 2009 or (b) our payment of $6.00 in cumulative distributions per common unit (beginning with our distribution with respect to the fourth quarter of 2007) to common unitholders. The Class D units are not entitled to receive cash distributions. No vote of our common unitholders will be required to convert the Class D units to common units.

Class E Units

Our Class E units, which we issued to accredited investors as part of our equity financing of the Cantera acquisition, have no distribution rights until our distribution with respect to the fourth quarter of 2008, when the Class E units then outstanding, if any, will become entitled to a special quarterly distribution equal to 110% of the quarterly common unit distribution. The Class E units will convert into common units upon payment of our distribution to common unitholders with respect to the third quarter of 2008, if the conversion terms of the Class E units are approved by our existing common unitholders and our Class C unitholders. Our Board of Directors has convened a special meeting of our unitholders for March 13, 2008 to consider this proposal.

Unitholder Return Performance Presentation

The performance graph below compares the cumulative total unitholder return on our common units, based on the market price of our common units, with the cumulative total return of the Standard & Poor's 500 Index (the "S&P 500 Index") and the Alerian MLP Total Return Index (the "Alerian Total Return Index"). The Alerian Total Return Index is a composite of the 50 most prominent energy master limited partnerships and limited liability companies calculated by Standard & Poor's using a float-adjusted market capitalization methodology. The Alerian Total Return Index is disseminated by the New York Stock Exchange real-time on a price return basis (NYSE: AMZX). Cumulative total return is based on annual total return, which assumes reinvested dividends or distributions for the period shown in the performance graph and assumes that $100 was invested in our company at the last reported sale price of our common units as reported on the NASDAQ ($11.35) (as adjusted for the common unit split) on November 9, 2004 (the day trading of our common units commenced) and in the S&P 500 Index and the Alerian Total Return Index on the same date. The results shown in the graph below are not necessarily indicative of future performance.



	November 9, 2004	December 31, 2004	2005	2006	2007
Copano (CPNO)	$100	$126[(a)]	$180[(b)]	$288[(c)]	$367[(d)]
Alerian MLP Total Return Index (AMZX)	$100	$106	$113	$142	$160
S&P 500 (SPX)	$100	$104	$107	$122	$126

(a) Based on the last sale price of our common units reported on the NASDAQ on December 31, 2004, as adjusted for the common unit split ($14.25).

(b) Based on the last sale price of our common units reported on the NASDAQ on December 30, 2005, as adjusted for the common unit split ($19.525).

(c) Based on the last sale price of our common units reported on the NASDAQ on December 29, 2006, as adjusted for the common unit split ($29.80).

(d) Based on the last sale price of our common units reported on the NASDAQ on December 31, 2007 ($36.35).

Notwithstanding anything to the contrary set forth in any of our previous or future filings under the Securities Act of 1933 or the Securities Exchange Act of 1934 that might incorporate this Annual Report or future filings with the SEC, in whole or in part, the preceding performance information shall not be deemed to be "soliciting material" or to be "filed" with the SEC or incorporated by reference into any filing except to the extent this performance presentation is specifically incorporated by reference therein.

Securities Authorized for Issuance Under Equity Compensation Plans

Please read the information incorporated by reference under Item 12, "Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters" of this Annual Report regarding securities authorized for issuance under our equity compensation plans, which information is incorporated by reference into this Item 5.

Issuer Purchases of Equity Securities

None.

Recent Sales of Unregistered Securities

None.

Item 6. *Selected Financial Data*

Selected Historical Consolidated Financial and Operating Data

The following table shows selected historical consolidated financial and operating data of Copano Energy, L.L.C. for the periods and as of the dates indicated. The selected historical consolidated financial data for the years ended December 31, 2007, 2006, 2005, 2004 and 2003 are derived from the audited consolidated financial statements of Copano Energy, L.L.C.

The following table includes the following non-GAAP financial measures: (1) EBITDA, (2) Adjusted EBITDA, (3) segment gross margin and (4) total segment gross margin. We define EBITDA as net income (loss) plus interest expense, provision for income taxes and depreciation and amortization expense, and Adjusted EBITDA as EBITDA plus (i) depreciation and amortization expense of equity investees in proportion to our ownership interest in each such equity investee, and (ii) amortization expense attributable to the difference between our carried investment in each equity investee and our underlying equity in its net assets. We define segment gross margin as our operating segment's revenue minus cost of sales. Cost of sales includes the: cost of natural gas and NGLs purchased by us from third parties, cost of natural gas and NGLs purchased by us from affiliates, costs we pay third parties to transport our volumes and costs we pay our affiliates to transport our volumes. We define total segment gross margin as the sum of our operating segments' gross margins and the results of our risk management activities that are included in corporate and other. This measure is a key component of internal financial reporting and is used by our senior management in deciding how to allocate capital resources among operating segments. For a reconciliation of these non-GAAP financial measures to their most directly comparable financial measures calculated and presented in accordance with GAAP, please read page 50 of this Annual Report.

The information in the following table is derived from, and should be read together with and is qualified in its entirety by reference to, our historical consolidated financial statements and the accompanying notes included in Item 8 of this Annual Report. The selected financial information should be read together with Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operation."

	Year Ended December 31,				
	2007[1]	2006	2005[2]	2004	2003
	(In thousands, except per unit data)				
Summary of Operations Data:					
Revenues	$1,141,660	$860,272	$ 747,743	$437,656	$384,571
Cost of sales	934,726	672,184	643,652	386,155	353,376
Operations and maintenance expenses	41,156	32,484	18,459	12,486	10,854
Depreciation and amortization	39,967	31,993	17,052	7,287	6,091
General and administrative expenses	34,638	26,535	18,156	9,217	5,849
Taxes other than income	2,637	2,061	1,178	770	926
Equity in (earnings) loss from unconsolidated affiliates[9]	(2,850)	(1,297)	(927)	(419)	127
Operating income	91,386	96,312	50,173	22,160	7,348
Interest income and other	2,854	1,706	640	85	43
Interest and other financing costs	(29,351)	(32,904)	(20,461)	(23,160)	(12,108)
Income before income taxes	64,889	65,114	30,352	(915)	(4,717)
Provision for income taxes	(1,714)	—	—	—	—
Net income (loss)	$ 63,175	$ 65,114	$ 30,352	$ (915)	$ (4,717)
Basic net income (loss) per common unit[3]	$ 1.48	$ 1.77	$ 1.20	$ (0.17)	$ (3.11)
Diluted net income (loss) per common unit[3]	$ 1.36	$ 1.75	$ 1.15	$ (0.17)	$ (3.11)

	Year Ended December 31,				
	2007[1]	2006	2005[2]	2004	2003
	(In thousands, except per unit data)				
Balance Sheet Data (at period end):					
Total assets	$1,769,083	$839,058	$ 792,750	$178,399	$161,709
Property, plant and equipment, net	694,727	566,927	532,320	119,683	117,032
Payables to affiliates	1,351	123	189	127	1,371
Long-term debt	630,773	255,000	398,000	57,000	57,898
Redeemable preferred units	—	—	—	—	60,982
Members' capital	894,136	472,586	281,803	82,356	(662)
Cash Flow Data:					
Net cash flow provided by (used in):					
Operating activities	$ 128,218	$ 91,679	$ 280	$ 17,697	$ 15,296
Investing activities	(727,052)	(70,291)	(491,708)	(8,920)	(6,192)
Financing activities	632,015	(7,201)	509,710	(6,369)	(9,633)
Other Financial Data:					
Total Segment Gross Margin:					
Oklahoma[4][5]	$ 115,099	$ 95,614	$ 40,683	$ —	$ —
Texas[6][7]	121,935	91,121	63,048	51,501	31,195
Rocky Mountains[8]	1,145	—	—	—	—
Segment gross margin	238,179	186,735	103,731	51,501	31,195
Corporate and other	(31,245)	1,353	360	—	—
Total Segment gross margin	$ 206,934	$188,088	$ 104,091	$ 51,501	$ 31,195
EBITDA[9]	$ 134,207	$130,011	$ 67,865	$ 29,532	$ 13,482
Adjusted EBITDA[10]	$ 140,626	$130,807	$ 68,285	$ 29,920	$ 13,831
Maintenance capital expenditures[11]	$ 9,062	$ 8,984	$ 5,394	$ 1,790	$ 2,281
Expansion capital expenditures[12]	884,290	53,298	487,578	7,130	3,911
Total capital expenditures	$ 893,352	$ 62,282	$ 492,972	$ 8,920	$ 6,192
Cash distributions per common unit[3]	$ 1.73	$ 1.29	$ 0.79	$ 0.51	$ —
Operating Data:					
Oklahoma:[4][5]					
Service throughput (Mcf/d)	165,059	147,166	132,011	—	—
Plant inlet volumes (Mcf/d)	117,423	102,556	87,977	—	—
NGLs produced (Bbls/d)	13,771	11,811	9,146	—	—
Crude pipeline throughput (Bbls/d)	2,417	—	—	—	—
Texas:					
Service throughput (Mcf/d)	608,171	543,303	567,002	591,431	585,410
Pipeline throughput (Mcf/d)[6]	276,987	237,897	214,774	220,970	238,800
Plant inlet volumes (Mcf/d)[6][7]	535,142	495,600	530,346	529,040	479,127
NGLs produced (Bbls/d)[6][7]	17,496	14,740	13,066	15,373	7,280
Rocky Mountains:					
Producer services throughput (Mcf/d)[8]	232,169	—	—	—	—

(1) Our summary financial and operating data as of and for the year ended December 31, 2007 include results attributable to our Cimmarron from May 1, 2007 through December 31, 2007 and Cantera from October 1, 2007 through December 31, 2007.

(2) Our summary financial and operating data as of and for the year ended December 31, 2005 include the results of our Oklahoma segment from August 1, 2005 (the date we acquired ScissorTail) through December 31, 2005.

(3) Net income (loss) per unit is based on the weighted average of total equivalent units outstanding during the periods presented. Prior periods have been adjusted to reflect the two-for-one split of our outstanding common units effective March 30, 2007. For periods prior to our IPO, equivalent units were calculated using the weighted average of pre-IPO common units and common special units adjusted by a conversion or exchange factor. The computation of diluted units outstanding for 2004 and 2003 excludes incremental units related to warrants previously held by preferred unitholders and employee unit options because these equity securities

had an anti-dilutive effect as a result of losses reported by us for these periods. Cash distributions for 2004 relate to the distributions paid to the pre-IPO unitholders prior to our IPO and are based on equivalent units.

(4) Plant inlet volumes and NGLs produced represent total volumes processed and produced by the Oklahoma segment at all plants, including our own plants and plants owned by third parties. For the year ended December 31, 2007, plant inlet volumes averaged 76,041 Mcf/d and NGLs produced averaged 9,349 Bbls/d for plants owned by the Oklahoma segment. For the year ended December 31, 2006, plant inlet volumes averaged 67,131 Mcf/d and NGLs produced averaged 7,989 Bbls/d for plants owned by the Oklahoma segment.

(5) Excludes volumes associated with our interest in Southern Dome. For the year ended December 31, 2007, plant inlet volumes for Southern Dome averaged 5,093 Mcf/d and NGLs produced averaged 244 Bbls/d. For the year ended December 31, 2006, plant inlet volumes for Southern Dome averaged 2,004 Mcf/d and NGLs produced averaged 88 Bbls/d.

(6) Excludes volumes associated with our interest in Webb Duval. Volumes transported by Webb Duval, net of intercompany volumes, were 82,755 Mcf/d, 102,691 Mcf/d, 106,826 Mcf/d, 104,438 Mcf/d, and 95,341 Mcf/d for the years ended December 31, 2007, 2006, 2005, 2004 and 2003, respectively.

(7) Plant inlet volumes and NGLs produced represent total volumes processed and produced by the Texas segment at all plants, including plants owned by the Texas segment and plants owned by third parties. Plant inlet volumes averaged 523,044 Mcf/d and NGLs produced averaged 16,317 barrels per day for the year ended December 31, 2007 for plants owned by the Texas segment. Plant inlet volumes averaged 495,600 Mcf/d and NGLs produced averaged 14,740 barrels per day for the year ended December 31, 2006 for plants owned by the Texas segment.

(8) Producer services throughput represents volumes we purchased for resale, volumes gathered utilizing our firm capacity gathering agreements with Fort Union and firm capacity volumes under our transportation agreements with WIC that we have released to producers in the Powder River Basin. Excludes results and volumes associated with our interests in Bighorn and Fort Union. Volumes transported by Bighorn and Fort Union were 216,584 Mcf/d and 604,850 Mcf/d, respectively, for the period from October 1, 2007 through December 31 2007.

(9) Under the equity method of accounting, these amounts include our equity in the (earnings) loss in affiliates.

(10) We calculate Adjusted EBITDA by adding to EBITDA (i) the portion of each of our equity investees' depreciation and amortization expense that is proportional to our ownership interest in each such equity investee, and (ii) the amortization expense attributable to the difference between our carried investment in each equity investee and our underlying equity in its net assets. We use Adjusted EBITDA to reflect the depreciation and amortization expense embedded in equity in earnings (loss) from unconsolidated affiliates. Adjusted EBITDA should not be considered an alternative to net income, operating income, cash flows from operating activities or any other measure of financial performance presented in accordance with GAAP.

(11) Maintenance capital expenditures are capital expenditures employed to replace partially or fully depreciated assets to maintain the existing operating capacity of our assets and to extend their useful lives, or other capital expenditures that are incurred in maintaining existing system volumes and related cash flows.

(12) Expansion capital expenditures represent capital expenditures made to expand or increase the efficiency of the existing operating capacity of our assets. Expansion capital expenditures include expenditures that facilitate an increase in volumes within our operations, whether through construction or acquisition. For example, expansion of compression facilities to increase throughput capacity or the acquisition of additional pipelines is considered expansion capital expenditures. Expenditures that reduce our operating costs will be considered expansion capital expenditures only if the reduction in operating expenses exceeds cost reductions typically resulting from routine maintenance. Costs for repairs and minor renewals to maintain facilities in operating condition, and which do not extend the useful life of existing assets, are considered operations and maintenance expenses (and not expansion capital expenditures) and are expensed as incurred.

The following table presents a reconciliation of the non-GAAP financial measures of (i) total segment gross margin (which consists of the sum of the segment gross margins of our three operating segments and corporate and other) to operating income and (ii) EBITDA and Adjusted EBITDA to the GAAP financial measures of net income (loss) and cash flows from operating activities on a historical basis for each of the periods indicated. For a detailed discussion of how we use these non-GAAP financial measures, please read Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operation — How We Evaluate Our Operations — Segment Gross Margin and — Adjusted EBITDA."

	Year Ended December 31,				
	2007	2006	2005	2004	2003
	(In thousands)				
Reconciliation of total segment gross margin to operating income:					
Operating income	$ 91,386	$ 96,312	$ 50,173	$22,160	$ 7,348
Add:					
Operations and maintenance expenses	41,156	32,484	18,459	12,486	10,854
Depreciation and amortization	39,967	31,993	17,052	7,287	6,091
General and administrative expenses	34,638	26,535	18,156	9,217	5,849
Taxes other than income	2,637	2,061	1,178	770	926
Equity in (earnings) loss from unconsolidated affiliates	(2,850)	(1,297)	(927)	(419)	127
Total segment gross margin	$206,934	$188,088	$104,091	$51,501	$31,195
Reconciliation of EBITDA and adjusted EBITDA to net income (loss):					
Net income (loss)	$ 63,175	$ 65,114	$ 30,352	$ (915)	$ (4,717)
Add:					
Depreciation and amortization	39,967	31,993	17,052	7,287	6,091
Interest and other financing costs	29,351	32,904	20,461	23,160	12,108
Provision for income taxes	1,714	—	—	—	—
EBITDA	$134,207	$130,011	$ 67,865	$29,532	$13,482
Add:					
Amortization of difference between the carried investment and the underlying equity in net assets of equity investments	4,589	(14)	(21)	(21)	(21)
Copano's share of depreciation and amortization included in equity in (earnings) loss from unconsolidated affiliates	1,830	810	441	409	370
Adjusted EBITDA	$140,626	$130,807	$ 68,285	$29,920	$13,831
Reconciliation of EBITDA and adjusted EBITDA to cash flows from operating activities:					
Cash flow provided by operating activities	$128,218	$ 91,679	$ 280	$17,697	$15,296
Add:					
Cash paid for interest and other financing costs	27,685	28,442	14,738	4,029	3,033
Equity in earnings (loss) from unconsolidated affiliates	2,850	1,297	927	419	(127)
Distributions from unconsolidated affiliates	(3,706)	—	—	—	—
Risk management assets	21,720	23,014	42,635	—	—
(Increase) decrease in working capital and other	(42,560)	(14,421)	9,285	7,387	(4,720)
EBITDA	$134,207	$130,011	$ 67,865	$29,532	$13,482
Add:					
Amortization of difference between the carried investment and the underlying equity in net assets of equity investments	4,589	(14)	(21)	(21)	(21)
Copano's share of depreciation and amortization included in equity in (earnings) loss from unconsolidated affiliates	1,830	810	441	409	370
Adjusted EBITDA	$140,626	$130,807	$ 68,285	$29,920	$13,831

Item 7. *Management's Discussion and Analysis of Financial Condition and Results of Operation*

You should read the following discussion of our financial condition and results of operation in conjunction with the historical consolidated financial statements and notes thereto included elsewhere in this Annual Report. For more detailed information regarding the basis of presentation for the following information, you should read the notes to the historical consolidated financial statements included in Item 8 of this Annual Report. In addition, you should review "— Forward-Looking Statements" contained in this Item 7 of this Annual Report and "— Risk Factors" contained in Item 1A of this Annual Report for information regarding forward-looking statements made in this discussion and certain risks inherent in our business. Other risks involved in our business are discussed under Item 7A, "Quantitative and Qualitative Disclosures about Market Risk."

Overview

We are a Delaware limited liability company formed in 2001 to acquire entities operating under the Copano name since 1992, and to serve as a holding company for our operating subsidiaries. Through our subsidiaries, we own and operate natural gas gathering and intrastate transmission pipeline assets and natural gas processing facilities in central and eastern Oklahoma and Texas, and as a result of the Cantera acquisition in October 2007, in Wyoming and Louisiana.

We manage our business and analyze and report our results of operations on a segment basis. Our operations are divided into three operating segments, Oklahoma, Texas and Rocky Mountains.

- Our Oklahoma segment provides midstream natural gas services in central and eastern Oklahoma, including gathering and related compression and dehydration services and natural gas processing, and was established as a segment upon our acquisition of ScissorTail on August 1, 2005. For the years ended December 31, 2007 and 2006, this segment generated approximately 56% and 51%, respectively, of our total segment gross margin.
- Our Texas segment provides midstream natural gas services in southeastern and northern Texas, including gathering and intrastate transmission of natural gas, and related services such as compression, dehydration and marketing. Our Texas segment also provides natural gas processing, conditioning and treating and NGL fractionation and transportation through our Houston Central plant, Sheridan NGL pipeline and, beginning in 2008, our Brenham NGL pipeline. In addition, our Texas segment owns a processing plant located in southwestern Louisiana. For the years ended December 31, 2007 and 2006, this segment generated approximately 58% and 48%, respectively, of our total segment gross margin.
- Our Rocky Mountains segment provides midstream natural gas services in the Powder River Basin of Wyoming, including gathering and treating of natural gas. The Rocky Mountains segment was established as a segment as a result of our acquisition of Cantera in October 2007. For the years ended December 31, 2007 and 2006, this segment generated approximately 1% and 0%, respectively, of our total segment gross margin, which represents margins derived from our producer services. The gross margin generated by this segment does not include results associated with our interests in Bighorn or Fort Union, which are reported as equity in earnings (loss) from unconsolidated affiliates.

Corporate and other relate to our risk management activities, intersegment eliminations, and other activities we perform or assets we hold that have not been allocated to any of our reporting segments. For the years ended December 31, 2007 and 2006, corporate and other generated approximately (15)% and 1%, respectively, of our total segment gross margin. Total segment gross margin is a non-GAAP financial measure, and includes the sum of our operating segments' gross margin and the results of our risk management activities that are included in corporate and other. For a reconciliation of total segment gross margin to its most directly comparable GAAP measure, please read Item 6 "Selected Financial Data."

Our total segment gross margins are determined primarily by five interrelated variables: (1) the volume of natural gas gathered or transported through our pipelines, (2) the volume of natural gas processed, conditioned or treated at our processing plants or, on our behalf, at third-party processing plants, (3) the level and relationship of natural gas and NGL prices, (4) our current contract portfolio and (5) our risk management activities. Because our profitability is a function of the difference between the revenues we receive from our operations, including revenues from the products we sell, and the costs associated with conducting our operations, including the costs of products we purchase, increases or decreases in our revenues alone are not necessarily indicative of increases or decreases in our profitability. To a large extent, our contract portfolio and the pricing environment for natural gas and NGLs will dictate increases or decreases in our profitability. For a summary of our most common contractual arrangements and management's analysis of our recent results of operations, please read "— Our Contracts" and "— Our Results of Operation." Our profitability is also dependent upon prices and market demand for natural gas and NGLs, which fluctuate with changes in market and economic conditions and other factors.

Our Oklahoma unit margins are, on the whole, positively correlated with NGL prices and natural gas prices. Increases in natural gas prices or decreases in NGL prices generally have a negative impact on our Texas unit margins, and, conversely, a reduction in natural gas prices or an increase in NGL prices generally has a positive impact on our Texas unit margins. The profitability of our Rocky Mountains operations is not significantly affected by the level of commodity prices. Substantially all of our Rocky Mountains contract portfolio, as well as Bighorn's and Fort Union's contract portfolios, consist of fixed-fee arrangements pursuant to which the gathering fee income represents an agreed rate per unit of throughput. The revenue we earn as a result of these arrangements is directly related to the volume of natural gas that flows through these systems and is not directly affected by commodity prices. To the extent a sustained decline in commodity prices results in a decline in volumes, however, our revenues under these arrangements would be reduced.

How We Evaluate Our Operations

We believe that investors benefit from having access to the same financial measures that our management uses in evaluating our performance. Our management uses a variety of financial and operational measurements to analyze our performance. These measurements include the following: (1) throughput volumes; (2) segment gross margin; (3) operations and maintenance expenses; (4) general and administrative expenses; (5) EBITDA; (6) Adjusted EBITDA and (7) distributable cash flow.

Throughput Volumes. Throughput volumes associated with our business are an important part of our operational analysis. We continually evaluate volumes coming into our plants and moving on our pipelines to ensure that we have adequate throughput to meet our financial objectives. Our performance at our processing plants is significantly influenced by both the volume of natural gas coming into the plant and the NGL content of the natural gas. In addition, we monitor fuel consumption because it has a significant impact on the gross margin realized from our processing or conditioning operations. Although we monitor fuel costs associated with our pipeline operations, these costs are frequently passed on to our producers.

It is also important that we continually add new volumes to our gathering systems to offset or exceed the normal decline of existing volumes that are attached to those systems. In monitoring volumes on our pipelines, managers of our Oklahoma and Texas segments evaluate what we refer to as service throughput, which consists of two components:

- The volume of natural gas transported or gathered through our pipelines, which we call pipeline throughput; and
- The volume of natural gas delivered to our wholly owned processing plants by third-party pipelines, excluding any volumes already included in our pipeline throughput.

In our Texas segment, we also compare pipeline throughput to service throughput to evaluate the volumes generated from our pipelines, as opposed to third-party pipelines. In Oklahoma, because no gas is delivered to our wholly owned plants other than by our pipelines, pipeline throughput and service throughput are equivalent. We also regularly assess the pipeline throughput of Bighorn and Fort Union.

In our Rocky Mountains segment, we evaluate producer services throughput, which we define as volumes we purchased for resale, volumes gathered utilizing our firm capacity gathering agreements with Fort Union and firm capacity volumes under our transportation agreements with WIC that we have released to producers.

Segment Gross Margin. We define segment gross margin as our operating segment's revenue minus cost of sales. Cost of sales includes the: cost of natural gas and NGLs purchased by us from third parties, cost of natural gas and NGLs purchased by us from affiliates, costs we pay third parties to transport our volumes and costs we pay our affiliates to transport our volumes. We define total segment gross margin as the sum of our operating segments' gross margins and the results of our risk management activities that are included in corporate and other. We view segment gross margin as an important performance measure of the core profitability of our operations. The total segment gross margin data reflects the financial impact of our contract portfolio on our company. This measure is a key component of internal financial reporting and is used by our senior management in deciding how to allocate capital resources among operating segments. With respect to our Oklahoma and Texas segments, our management analyzes segment gross margin per unit of service throughput. With respect to our Rocky Mountains segment, our management analyzes segment gross margin per unit of producer services throughput. Also, our management analyzes the cash distributions our Rocky Mountains segment receives from Bighorn and Fort Union. Both our segment gross margin and total segment gross margin is reviewed monthly for consistency and trend analysis.

To isolate and consistently track changes in commodity price relationships and their impact on our Texas segment's results from its processing operations, we calculate a hypothetical "standardized" processing margin. This processing margin is based on a fixed set of assumptions, with respect to liquids composition and fuel consumption per recovered gallon, which we believe is generally reflective of our business. Because these assumptions are held stable over time, changes in underlying natural gas and NGL prices drive changes in the standardized processing margin. Our financial results are not derived from this standardized processing margin and the standardized margin is not derived from our financial results. However, we believe this calculation is representative of the current operating commodity price environment of our Texas processing operations and we use this calculation to track commodity price relationships. Our results of operations may not necessarily correlate to the changes in our standardized processing margin because of the impact of factors other than commodity prices such as volumes, changes in NGL composition, recovery rates and variable contract terms. Our standardized processing margins averaged $0.4578, $0.2808 and $0.0899 per gallon during the years ended December 31, 2007, 2006 and 2005, respectively. The average standardized processing margin for the period from January 1, 1989 through December 31, 2007 is $0.12 per gallon.

Operations and Maintenance Expenses. Operations and maintenance expenses are costs associated with the operations of a specific asset. Direct labor, insurance, repair and maintenance, utilities and contract services comprise the most significant portion of operations and maintenance expenses. These expenses remain relatively stable across broad volume ranges and fluctuate slightly depending on the activities performed during a specific period. A portion of our operations and maintenance expenses are incurred through Copano Operations, an affiliate of our company and controlled by John R. Eckel, Jr., the Chairman of our Board of Directors and our Chief Executive Officer. Under the terms of our arrangement with Copano Operations, we have agreed to reimburse it, at cost, for the operations and maintenance expenses it incurs on our behalf, which consist primarily of payroll costs.

General and Administrative Expenses. Our general and administrative expenses include the cost of employee and officer compensation and related benefits, office lease and expenses, professional fees, information technology expenses, as well as other expenses not directly associated with our field operations. A portion of our general and administrative expenses are incurred through Copano Operations, an affiliate of our company. Under the terms of our arrangement with Copano Operations, we have agreed to reimburse it, at cost, for the general and administrative expenses it incurs on our behalf. For more information concerning our arrangement with Copano Operations, please see Note 9, "Related Party Transactions" to the consolidated financial statements beginning on page F-1 of this Annual Report.

Adjusted EBITDA. We define EBITDA as net income (loss) plus interest expense, provision for income taxes and depreciation and amortization expense. Because a portion of our net income (loss) is attributable to equity in earnings (loss) from our equity investees (which now include Big Horn and Fort Union in addition to Webb Duval and Southern Dome), our management also calculates Adjusted EBITDA to reflect the depreciation and amortization expense embedded in equity in earnings (loss) from unconsolidated affiliates. Specifically, our management determines Adjusted EBITDA by adding to EBITDA (i) the portion of each equity investee's depreciation and amortization expense which is proportional to our ownership interest in that equity investee and (ii) the amortization expense attributable to the difference between our carried investment in each equity investee and our underlying equity in its net assets.

External users of our financial statements such as investors, commercial banks and research analysts use EBITDA or Adjusted EBITDA, and our management uses Adjusted EBITDA, as a supplemental financial measure to assess:

- the financial performance of our assets without regard to financing methods, capital structure or historical cost basis;
- the ability of our assets to generate cash sufficient to pay interest costs and support our indebtedness;
- our operating performance and return on capital as compared to those of other companies in the midstream energy sector, without regard to financing or capital structure; and
- the viability of acquisitions and capital expenditure projects and the overall rates of return on alternative investment opportunities.

EBITDA is also a financial measure that, with certain negotiated adjustments, is reported to our lenders and is used to compute our financial covenants under our senior secured revolving credit facility. Neither EBITDA nor Adjusted EBITDA should be considered an alternative to net income, operating income, cash flows from operating activities or any other measure of financial performance presented in accordance with GAAP.

Distributable Cash Flow. We define distributable cash flow as net income or loss plus: (i) depreciation and amortization expense; (ii) cash distributions received from investments in unconsolidated affiliates and equity losses from such unconsolidated affiliates; (iii) reimbursements by our pre-IPO investors of certain general and administrative expenses in excess of the "G&A Cap" defined in our limited liability company agreement; (iv) the subtraction of maintenance capital expenditures, (v) the subtraction of equity in earnings from unconsolidated affiliates and (vi) the addition of losses or subtraction of gains relating to other miscellaneous non-cash amounts affecting net income for the period. Maintenance capital expenditures are capital expenditures employed to replace partially or fully depreciated assets to maintain the existing operating capacity of our assets and to extend their useful lives, or other capital expenditures that are incurred in maintaining existing system volumes and related cash flows. Distributable cash flow is a significant performance metric used by senior management to compare basic cash flows generated by us (prior to the establishment of any retained cash reserves by our Board of Directors) to the cash distributions we expect to pay our unitholders. Using this metric, management can quickly compute the coverage ratio of estimated cash flows to planned cash distributions. Distributable cash flow is also an important non-GAAP financial measure for our unitholders since it serves as an indicator of our success in providing a cash return on investment. Specifically, this financial measure indicates to investors whether or not we are generating cash flow at a level that can sustain or support an increase in our quarterly distribution rates. Distributable cash flow is also a quantitative standard used throughout the investment community with respect to publicly traded partnerships and limited liability companies because the market value of a unit of such an entity is significantly influenced by the amount of cash distributions the entity can pay to a unitholder.

How We Manage Our Operations

Our management team uses a variety of tools to manage our business. These tools include: (i) our economic models; (ii) flow and transaction monitoring systems (iii) producer activity evaluation and reporting; and (iv) imbalance monitoring and control.

Our Economic Models. We utilize our economic models to determine (i) whether we should elect payment using a percentage-of-index basis or a percentage-of-proceeds basis under certain Oklahoma "switch" contracts, which allow us to choose the basis of payment (ii) whether we should reduce the ethane extracted from certain natural gas processed by some of our processing plants and (iii) whether we should process or condition natural gas at our Houston Central plant.

Flow and Transaction Monitoring Systems. We utilize automated systems that track commercial activity on each of our Texas segment pipelines and monitor the flow of natural gas on all of our pipelines. For our Oklahoma segment, we electronically monitor pipeline volumes and operating conditions at certain key points along our pipeline systems. In our Texas segment, we designed and implemented software that tracks each of our natural gas transactions, which allows us to continuously track volumes, pricing, imbalances and estimated revenues from our pipeline assets. Additionally, we utilize automated Supervisory Control and Data Acquisition (SCADA) systems, which assists management in monitoring and operating our Texas segment. Bighorn, which our Rocky Mountains segment operates, also utilizes a SCADA system. The SCADA systems allow us to monitor our assets at remote locations and respond to changes in pipeline operating conditions.

Producer Activity Evaluation and Reporting. We monitor the producer drilling and completion activity in our Texas and Oklahoma areas of operation to identify anticipated changes in production and potential new well attachment opportunities. The continued attachment of natural gas production to our pipeline systems is critical to our business and directly impacts our financial performance. Using a third-party electronic reporting system, we receive daily reports of new drilling permits and completion reports filed with the state regulatory agency that governs these activities in Texas and Oklahoma. Additionally, our field personnel report the locations of new wells in their respective areas and anticipated changes in production volumes to supply representatives and operating personnel. These processes enhance our awareness of new well activity in our operating areas and allow us to be responsive to producers in connecting new volumes of natural gas to our pipelines. In all our operating segments, we meet with producers and obtain drilling schedules, if available, to assist us in anticipating future activity on our pipelines.

Imbalance Monitoring and Control. We continually monitor volumes received and volumes delivered on behalf of third parties to ensure we remain within acceptable imbalance limits during the calendar month. We seek to reduce imbalances because of the inherent commodity price risk that results when receipts and deliveries of natural gas are not balanced concurrently. We have implemented "cash-out" provisions in many of our transportation agreements to reduce this commodity price risk. Cash-out provisions require that any imbalance that exists between a third party and us at the end of a calendar month is settled in cash based upon a pre-determined pricing formula. This provision ensures that imbalances under such contracts are not carried forward from month-to-month and revalued at higher or lower prices.

Our Contracts

In connection with our operations, we seek to execute contracts with producers and shippers that provide us with positive gross margin in all natural gas and NGL pricing environments. We enter into a variety of contractual arrangements, including fee-based arrangements, percentage-of-proceeds arrangements, percentage-of-index arrangements and keep-whole with fee arrangements. Actual contract terms vary based upon a variety of factors including gas quality, pressures of natural gas production relative to downstream transporter pressure requirements, the competitive environment at the time the contract is executed and customer requirements. Our contract mix and, accordingly, our exposure to natural gas and NGL prices, may change as a result of changes in producer preferences, gas quality, downstream transporter gas quality specifications, our expansion in regions where some types of contracts are more common and other market factors.

The following is a summary of our most common contractual arrangements for gathering, transporting, processing and conditioning natural gas:

Fee-Based Arrangements. Under fee-based arrangements, producers or shippers pay us an agreed rate per unit of throughput to gather or transport their natural gas. The agreed rate may be a fixed fee or based upon a percentage of index price. The revenue we earn from fixed-fee arrangements is directly related to the volume of natural gas that flows through our systems and is not directly dependent on commodity prices. However, to the extent a sustained decline in commodity prices results in a decline in volumes, our revenues from these arrangements would be reduced. When the fee is based upon a percentage of index price, the fee decreases in periods of low natural gas prices and increases during periods of high natural gas prices.

Percentage-of-Proceeds Arrangements. Under percentage-of-proceeds arrangements, we generally gather and process natural gas on behalf of producers and sell the residue gas and NGL volumes at index-related prices. We remit to producers an agreed upon percentage of the proceeds we receive from the sale of residue gas and NGLs. Under these types of arrangements, our revenues and gross margins increase as natural gas and NGL prices increase and our revenues and gross margins decrease as natural gas and NGL prices decrease.

Percentage-of-Index Arrangements. Under percentage-of-index arrangements, we purchase natural gas at either (i) a percentage discount to a specified index price, (ii) a specified index price less a fixed amount or (iii) a percentage discount to a specified index price less an additional fixed amount. We then gather, deliver and resell the natural gas at an index-based price. The gross margins we realize under the arrangements described in clauses (i) and (iii) above decrease in periods of low natural gas prices and increase during months of high natural gas prices because these gross margins are based on a percentage of the index price.

Keep-Whole with Fee Arrangements. Under keep-whole with fee arrangements, we receive natural gas from producers and third-party transporters, either process or condition the natural gas at our election, sell the resulting NGLs to third parties at market prices for our account and redeliver the residue gas to the producer or third-party transporter. We determine whether to process or condition the natural gas based upon the relationship between natural gas and NGL prices. Because the extraction of NGLs from the natural gas during processing or conditioning reduces the Btus of the natural gas, we also must purchase natural gas at market prices for return to producers or third-party transporters to keep them whole. Accordingly, under these arrangements, our revenues and gross margins increase as the price of NGLs increase relative to the price of natural gas, and our revenues and gross margins decrease as the price of natural gas increases relative to the price of NGLs. In the latter case, we are generally able to reduce our commodity price exposure by conditioning rather than processing the natural gas. Under our keep-whole with fee arrangements, we also charge producers and third-party transporters a conditioning fee, at all times or in certain circumstances depending upon the terms of the particular contract. These fees provide us additional revenue and compensate us for the services required to redeliver natural gas that meets downstream pipeline quality specifications. It is generally not our policy to enter into new keep-whole contracts without fee arrangements or pricing provisions that provide positive gross margins during conditioning periods. For a discussion of our processing and conditioning capabilities, please read Item 1, “Business — Our Operations — Texas” of this Annual Report. In our Oklahoma and Texas segments, we often provide services under contracts that reflect a combination of these contract types, while substantially all of our Rocky Mountains segment’s contracts reflect fixed-fee arrangements. Fort Union’s and Bighorn’s contractual arrangements are entirely fixed-fee.

In addition to providing for compensation for our gathering, transportation, processing or conditioning services, in many cases, our contracts for natural gas supplies also allow us to charge producers fees for treating, compression, dehydration or other services. Additionally, we may share a fixed or variable portion of our processing margins with the producer or third-party transporter in the form of “processing upgrade” payments during periods where such margins are in excess of an agreed-upon amount.

Our Contracts with Kinder Morgan Texas Pipeline. We use KMTP as a transporter because our Houston Central plant straddles its 30-inch-diameter Laredo-to-Katy pipeline, which allows us to move natural gas from our pipeline systems in South Texas and near the Texas Gulf Coast to our Houston Central plant and downstream markets. KMTP’s pipeline also delivers to the Houston Central plant natural gas for its own account, which we refer to as “KMTP Gas.” Under agreements with KMTP and with other producers or transporters whose gas KMTP has delivered to us, we process or condition the gas and sell the NGLs to third parties at market prices. Under our processing agreement with KMTP, after processing or conditioning KMTP Gas, we make up for the reduction in Btus resulting from extracting NGLs from the natural gas stream using natural gas that we purchase from producers at market prices Our processing agreement with KMTP also provides that we make a processing payment to KMTP during periods of favorable processing margins, which allows KMTP to share in the profitability of processing gas. During periods of unfavorable processing margins, KMTP instead pays us the lesser of (i) the difference between the processing margin and a specified threshold or (ii) a fixed fee per Mcf of KMTP Gas.

We also have a gas transportation agreement and a related gas sales agreement with KMTP. Each of our agreements with KMTP extends through January 31, 2011, with automatic annual renewals thereafter unless canceled by either party upon 180 days’ prior written notice, in the case of the processing and gas transportation agreements, or 30 days’ prior written notice, in the case of the sales agreement.

For the year ended December 31, 2007, approximately 76% of the natural gas volumes processed or conditioned at our Houston Central plant were delivered to the plant through the KMTP Laredo-to-Katy pipeline, while the remaining 24% were delivered directly to the plant from our Houston Central gathering systems. Of the volumes delivered from the KMTP Laredo-to-Katy pipeline, approximately 31% were from our gathering systems, while 69% were "KMTP Gas." Of the total NGLs extracted at the plant during this period, 32% originated from KMTP Gas, and 68% from our South Texas gathering systems, including our gathering systems connected directly to the plant.

Our Long-Term Growth Strategy

Our growth strategy contemplates complementary acquisitions of midstream assets in our operating areas as well as capital expenditures to enhance our ability to increase cash flows from our existing assets. We intend to pursue acquisitions and capital expenditure projects that we believe will allow us to capitalize on our existing infrastructure, personnel and relationships with producers and customers to provide midstream services. We also evaluate acquisitions in new geographic areas, including other areas of Texas, Oklahoma and New Mexico and the Rocky Mountains region, to the extent they present growth opportunities similar to those we are pursuing in our existing areas of operations. To successfully execute our growth strategy, we will require access to capital on competitive terms. We believe that our long-term cost of equity capital will be favorable because unlike many of our competitors that are master limited partnerships, or MLPs, neither our management nor any other party holds incentive distribution rights that entitle them to increasing percentages of cash distributions as higher per unit levels of cash distributions are received. We intend to finance future acquisitions primarily through the issuance of debt and equity. For a more detailed discussion of our capital resources, please read "— Liquidity and Capital Resources."

Acquisition Analysis. In analyzing a particular acquisition, we consider the operational, financial and strategic benefits of the transaction. Our analysis includes location of the assets, strategic fit of the assets in relation to our business strategy, expertise required to manage the assets, capital required to integrate and maintain the assets, and the competitive environment of the area where the assets are located. From a financial perspective, we analyze the rate of return the assets will generate under various case scenarios, comparative market parameters and the anticipated earnings and cash flow capabilities of the assets.

Capital Expenditure Analysis. We make capital expenditures either to maintain our assets or the supply of natural gas volumes to our assets or for expansion projects to increase our gross margin. Maintenance capital expenditures are capital expenditures employed to replace partially or fully depreciated assets to maintain the existing operating capacity of our assets and to extend their useful lives, or other capital expenditures that are incurred in maintaining existing system volumes and related cash flows. Expansion capital expenditures represent capital expenditures made to expand or increase the efficiency of the existing operating capacity of our assets. Expansion capital expenditures include expenditures that facilitate an increase in volumes within our operations, whether through construction or acquisition. Expenditures that reduce our operating costs will be considered expansion capital expenditures only if the reduction in operating expenses exceeds cost reductions typically resulting from routine maintenance. Our decisions whether to spend capital on expansion projects are generally based on anticipated earnings, cash flow and rate of return of the assets.

Items Impacting Comparability of Our Financial Results

Our Acquisitions

Since our inception in 1992, we have grown through a combination of numerous acquisitions, including the acquisition of our Oklahoma and Rocky Mountains segments, as well as significant expansion and enhancement projects related to our assets. Our historical acquisitions were completed at different dates and with a number of sellers and were accounted for using the purchase method of accounting. Under the purchase method of accounting, results of operations from such acquisitions are recorded in the financial statements only from the date of acquisition. As a result, our historical results of operations for the periods presented may not be comparable, as they reflect the results of operations of a business that has grown significantly due to acquisitions. For example, the year ended December 31, 2005 is not comparable to the years ended December 31, 2006 and 2007 because of our acquisition of ScissorTail in August 2005 (which comprised our entire Oklahoma segment until our acquisition of Cimmarron in May 2007) and the years ended December 31, 2005 and 2006 are not comparable to the year ended December 31, 2007 because of our acquisitions of Cimmarron in May 2007 and Cantera in October 2007.

Adoption of SFAS No. 123(R)

On January 1, 2006, we adopted Statement of Financial Accounting Standards ("SFAS") No. 123(R) which requires the grant date fair value of the equity compensation award to be recognized as expense over the vesting period of the award. We have elected to use the modified prospective method and accordingly, results for prior periods were not restated. Prior to the adoption of SFAS No. 123(R), we recognized equity-based compensation expense for awards with graded vesting by treating each vesting tranche as a separate award and recognizing compensation expense ratably for each tranche. For equity awards outstanding as of January 1, 2006, the remaining unrecognized compensation expense as of January 1, 2006 is expensed on a straight-line basis (net of estimated forfeitures) over the remaining vesting period of the award. We treat equity awards granted after the adoption of SFAS No. 123(R), as a single award and recognize equity-based compensation expense on a straight-line basis (net of estimated forfeitures) over the employee service or vesting period. Equity-based compensation expense is recorded in operations and maintenance expenses and general and administrative expenses in our consolidated statements of operations. The adoption of this statement did not have a material effect on our financial position or results of operations. Please read Notes 2 and 8 to the Consolidated Financial Statements contained in Item 8 of this Annual Report.

Our Results of Operation

	Year Ended December 31,		
	2007[1]	2006	2005[2]
		($ in thousands)	
Total segment gross margin[3]	$206,934	$188,088	$104,091
Operations and maintenance expenses	41,156	32,484	18,459
Depreciation and amortization	39,967	31,993	17,052
General and administrative expenses	34,638	26,535	18,156
Taxes other than income	2,637	2,061	1,178
Equity in earnings from unconsolidated affiliates	(2,850)	(1,297)	(927)
Operating income	91,386	96,312	50,173
Interest and other financing costs, net	(26,497)	(31,198)	(19,821)
Income before income taxes	64,889	65,114	30,352
Provision for income taxes	(1,714)	—	—
Net income	$ 63,175	$ 65,114	$ 30,352
Total segment gross margin:			
Oklahoma[4][5]	$115,099	$ 95,614	$ 40,683
Texas[6][7]	121,935	91,121	63,048
Rocky Mountains[8]	1,145	—	—
Segments gross margin	238,179	186,735	103,731
Corporate and other	(31,245)	1,353	360
Total segment gross margin[3]	$206,934	$188,088	$104,091
Segment gross margin per unit:			
Oklahoma:			
Service throughput ($/MMBtu)[4][5]	$ 1.580	$ 1.48	$ 1.68
Texas:			
Service throughput ($/MMBtu)[6][7]	$ 0.520	$ 0.44	$ 0.29
Rocky Mountains:			
Producer services throughput ($/MMBtu)[8]	$ 0.055	—	—

	Year Ended December 31,		
	2007[1]	2006	2005[2]
	($ in thousands)		
Volumes:			
Oklahoma:[4][5]			
Service throughput (MMBtu/d)	199,906	177,368	158,334
Plant inlet volumes (MMBtu/d)	144,050	125,364	106,877
NGLs produced (Bbls/d)	13,771	11,811	9,146
Crude pipeline throughput (Bbls/d)	2,417	—	—
Texas:			
Service throughput (MMBtu/d)	645,724	573,141	597,888
Pipeline throughput (MMBtu/d)[6]	299,484	254,886	232,280
Plant inlet volumes (MMBtu/d)[6][7]	567,306	522,465	561,085
NGLs produced (Bbls/d)[6][7]	17,496	14,740	13,066
Rocky Mountains:			
Producer services throughput (MMBtu/d)[8]	224,525	—	—
Maintenance capital expenditures[9]	$ 9,062	$ 8,984	$ 5,394
Expansion capital expenditures[10]	884,290	53,298	487,578
Total capital expenditures	$893,352	$ 62,282	$492,972
Operations and maintenance expenses:			
Oklahoma	$ 20,711	$ 17,185	$ 5,917
Texas	20,437	15,299	12,542
Rocky Mountains	8	—	—
Total operations and maintenance expenses	$ 41,156	$ 32,484	$ 18,459

(1) Our summary financial and operating data for the year ended December 31, 2007 include results attributable to Cimmarron acquisition from May 1, 2007 through December 31, 2007 and Cantera (which comprises our entire Rocky Mountains segment) from October 1, 2007 through December 31, 2007. The results of operations from assets acquired in the Cimmarron acquisition are included in the Oklahoma segment and Texas segments.

(2) Our summary financial and operating data for the year ended December 31, 2005 include the results of our Oklahoma segment from August 1, 2005 the date we acquired ScissorTail) through December 31, 2005.

(3) Total segment gross margin is a non-GAAP financial measure. For a reconciliation of total segment gross margin to its most directly comparable GAAP measure, please read Item 6 “Selected Financial Data” of this Annual Report.

(4) Plant inlet volumes and NGLs produced represent total volumes processed and produced by the Oklahoma segment at all plants, including our owned plants and plants owned by third parties. For the year ended December 31, 2007, Plant inlet volumes averaged 93,173 MMBtu/d and NGLs produced averaged 9,349 Bbls/d for plants owned by the Oklahoma segment. For the year ended December 31, 2006, plant inlet volumes averaged 82,045 MMBtu/d and NGLs produced averaged 7,989 Bbls/d for plants owned by the Oklahoma segment.

(5) Excludes volumes associated with our interest in Southern Dome. For the year ended December 31, 2007, plant inlet volumes for Southern Dome averaged 6,061 MMBtu/d and NGLs produced averaged 244 Bbls/d. For the year ended December 31, 2006, plant inlet volumes for Southern Dome averaged 2,353 MMBtu/d and NGLs produced averaged 88 Bbls/d.

(6) Excludes results and volumes associated with our interest in Webb Duval. Volumes transported by Webb Duval, net of intercompany volumes, were 93,887 MMBtu/d, 117,303 MMBtu/d and 121,864 MMBtu/d for the years ended December 31 2007, 2006 and 2005, respectively.

(7) Plant inlet volumes and NGLs produced represent total volumes processed and produced by the Texas segment at all plants, including plants owned by the Texas segment and plants owned by third parties. Plant inlet volumes averaged 552,690 MMBtu/d and NGLs produced averaged 16,317 barrels per day for the year ended December 31, 2007 for plants owned by the Texas segment. Plant inlet volumes averaged 522,465 MMBtu/d and NGLs produced averaged 14,740 barrels per day for the year ended December 31, 2006 for plants owned by the Texas segment.

(8) Producer services throughput represents volumes we purchased for resale, volumes gathered utilizing our firm capacity gathering agreements with Fort Union and firm capacity volumes under our transportation agreements with WIC that we have released to producers in the Powder River Basin. Excludes results and volumes associated with our interests in Bighorn and Fort Union. Volumes transported by Bighorn and Fort Union were 211,510 MMBtu/d and 576,700 MMBtu/d, respectively, for the period from October 1, 2007 through December 31 2007.

(9) Maintenance capital expenditures are capital expenditures employed to replace partially or fully depreciated assets to maintain the existing operating capacity of our assets and to extend their useful lives, or other capital expenditures that are incurred in maintaining existing system volumes and related cash flows.

(10) Expansion capital expenditures represent capital expenditures made to expand or increase the efficiency of the existing operating capacity of our assets. Expansion capital expenditures include expenditures that facilitate an increase in volumes within our operations, whether through construction or acquisition. For example, expansion of compression facilities to increase throughput capacity or the acquisition of additional pipelines is considered expansion capital expenditures. Expenditures that reduce our operating costs will be considered expansion capital expenditures only if the reduction in operating expenses exceeds cost reductions typically resulting from routine maintenance. Costs for repairs and minor renewals to maintain facilities in operating condition, and which do not extend the useful life of existing assets, are considered operations and maintenance expenses (and not expansion capital expenditures) and are expensed as incurred.

(11) Under the equity method of accounting, these amounts include our equity in the (earnings) loss in affiliates.

Year Ended December 31, 2007 Compared with Year Ended December 31, 2006

Oklahoma Segment Gross Margin. Oklahoma segment gross margin was $115.1 million for the year ended December 31, 2007 compared to $95.6 million for the year ended December 31, 2006, an increase of $19.5 million, or 20%. The increase in segment gross margin resulted primarily from increases in NGLs produced, plant inlet volumes and service throughput of 17%, 15% and 13%, respectively, and higher NGL prices. The Cimmarron assets included in the Oklahoma segment accounted for 8% of the increase in NGLs produced, 12% of the increase in Plant inlet volumes and 11% of the increased service throughput for this segment. NGLs produced at the Paden plant increased 22% during 2007 as compared to 2006. Throughput on the crude oil system acquired in May 2007 as part of the Cimmarron acquisition averaged 3,600 barrels per day for the period from May 1, 2007 through December 31, 2007. During 2007, the CenterPoint East natural gas index price averaged $6.07 per MMBtu compared to $6.15 per MMBtu during 2006, a decrease of $0.08, or 1.3%.

Texas Segment Gross Margin. Texas segment gross margin was $121.9 million for the year ended December 31, 2007 compared to $91.1 million for year ended December 31, 2006, an increase of $30.8 million, or 34%. The increase was primarily attributable to increased service throughput and improvements of $26.5 million attributable to increased NGL margins and output at our Houston Central plant. During year ended December 31, 2007, the HSC natural gas index price averaged $6.58 per MMBtu compared to $6.53 per MMBtu during the year ended December 31, 2006, an increase of $0.05, or 1%. For a discussion of the commodity price environment affecting our Texas segment, please read "— How We Evaluate Our Operations — Segment Gross Margin."

Rocky Mountains Segment Gross Margin. From our acquisition of the Rocky Mountains segment in October 2007 through December 31, 2007, the segment gross margin totaled $1.1 million. During this period, producer services throughput averaged 224,525 MMBtu/d with an average margin of $0.055 per MMBtu. Producer services throughput represents volumes we purchased for resale, volumes gathered utilizing our firm capacity gathering agreements with Fort Union and firm capacity volumes under our transportation agreements with WIC that we have released to producers in the Powder River Basin.

Corporate and Other. The corporate and other loss includes our commodity risk management activities of $31.2 million for the year ended December 31, 2007 compared to a gain of $1.4 million for the year ended December 31, 2006. The loss for the year ended December 31, 2007 is comprised of $21.0 million of non-cash amortization expense related to purchased commodity derivatives and $10.1 million of unrealized losses related to mark-to-market changes and ineffective portions of hedges and $0.1 million of net cash settlements paid with respect to expired commodity derivatives. The gain for the year ended December 31, 2006 consisted of (i) $12.1 million of net cash settlements on expired commodity derivatives offset by (ii) $10.4 million of non-cash amortization expense related to purchased commodity derivatives and $0.3 million of unrealized losses related to the ineffective portion of hedges.

Operations and Maintenance Expenses. Operations and maintenance expenses totaled $41.2 million for the year ended December 31, 2007 compared to $32.5 million for the year ended December 31, 2006. The increase of $8.7 million, or 27%, is primarily attributed to (i) increased labor, compression, insurance, materials and supplies and repair expenses in our Oklahoma segment of $3.5 million including activities associated with the Cimmarron assets acquired in May 2007 and (ii) increased labor, chemicals, utilities, lease rentals and repair and maintenance expenses of $5.2 million in our Texas segment including activities associated with the Tri-County assets acquired in May 2007 as part of Cimmarron.

Depreciation and Amortization. Depreciation and amortization totaled $40.0 million for the year ended December 31, 2007 compared with $32.0 million for the year ended December 31, 2006, an increase of $8.0 million, or 25%. This increase relates primarily to additional depreciation and amortization associated with acquisitions and capital expenditures made after December 31, 2006, including the Cimmarron acquisition in May 2007 and the Cantera acquisition in October 2007.

General and Administrative Expenses. General and administrative expenses totaled $34.6 million for the year ended December 31, 2007 compared with $26.5 million for the year ended December 31, 2006, an increase of $8.1 million, or 30%. The increase primarily relates to (i) expenses related to additional personnel, consultants and office space and compensation adjustments of $4.5 million, (ii) expenses incurred by our Oklahoma segment of $1.6 million including expenses related to Cimmarron assets acquired in May 2007, (iii) legal and accounting fees of $1.1 million, (iv) non-cash compensation expense related to the amortization of the fair value of restricted units, phantom units and unit options issued to employees and directors of $0.7 million, (v) costs associated with the Rocky Mountains segment acquired in October 2007 of $0.6 million and (vi) costs of preparing and processing tax K-1s to unitholders of $0.4 million offset by a decrease of $0.8 million related to expenses associated with acquisition initiatives that were not consummated.

Interest Expense. Interest and other financing costs totaled $29.4 million for the year ended December 31, 2007 compared with $32.9 million for the year ended December 31, 2006, a decrease of $3.5 million, or 11%. Interest expense related to our senior secured revolving credit facility totaled $8.2 million (net of $1.2 million of capitalized interest and settlements under our interest rate swaps) and $8.8 million (net of $1.0 million of capitalized interest and settlements under our interest rate swaps) for the year ended December 31, 2007 and 2006, respectively. Interest on our Senior Notes totaled $19.5 million and $16.5 million for the year ended December 31, 2007 and 2006, respectively. Interest on our unsecured term loan and our term loan facility totaled $3.1 million for the year ended December 31, 2006. Amortization of debt issue costs totaled $1.7 million and $4.5 million for the year ended December 31, 2007 and 2006, respectively. Amortization of debt issue costs for the year ended December 31, 2006 included a one-time charge of $1.7 million related to the reduction of the commitment under the Credit Facility from $350 million to $200 million. Average borrowings under our credit arrangements were $376.5 million and $373.2 million with average interest rates of 7.9% and 8.3% for the year ended December 31, 2007 and 2006, respectively. Please read "— Liquidity and Capital Resources — Description of Our Indebtedness" for a detailed discussion of our senior secured revolving credit facility and our Senior Notes.

Year Ended December 31, 2006 Compared with Year Ended December 31, 2005

Oklahoma Segment Gross Margin. For the year ended December 31, 2006, segment gross margin for our Oklahoma segment totaled $95.6 million. During the same period, this segment gathered or transported an average of 177,368 MMBtu/d of natural gas on its pipelines, processed an average of 125,364 MMBtu/d of natural gas and produced an average of 11,811 Bbls/d of NGLs. Our Oklahoma segment was established upon our acquisition of ScissorTail on August 1, 2005 and during the period from August 1, 2005 through December 31, 2005, segment gross margin for our Oklahoma segment totaled $40.7 million. During the same period, this segment gathered or transported an average of 158,334 MMBtu/d of natural gas on its pipelines, processed an average of 106,877 MMBtu/d of natural gas and produced an average of 9,146 Bbls/d of NGLs.

Texas Segment Gross Margin. Texas segment gross margin was $91.1 million for the year ended December 31, 2006 compared to $63.0 million for the year ended December 31, 2005, an increase of $28.1 million, or 45%. This increase resulted from a 10% increase in pipeline throughput during the year ended December 31, 2006 and improvements of $31.8 million attributable to increased NGL margins and output at our Houston Central plant. During the year ended December 31, 2006, the HSC natural gas index price averaged $6.53 per MMBtu compared to $7.54 per MMBtu during the year ended December 31, 2005, a decrease of $1.01, or 13%. For a discussion of the commodity price environment, please read "— How We Evaluate Our Operations — Segment Gross Margin."

Corporate and Other. The corporate and other gain includes our commodity risk management activities of $1.4 million for the year ended December 31, 2006 compared to a gain of $0.4 million for the year ended December 31, 2005. The gain for the year ended December 31, 2006 is attributable to our commodity risk management activities and is comprised of (i) $12.1 million of net cash settlements received with respect to expired put contracts offset by (ii) $10.4 million of amortization expense related to purchased put derivatives and (iii) $0.3 million of unrealized losses related to the ineffective portion of our hedges. The gain for the year ended December 31, 2005 related to our commodity risk management activities commencing in July 2005 that were accounted for on a mark-to-market basis through October 24, 2005.

Operations and Maintenance Expenses. Operations and maintenance expenses totaled $32.5 million for the year ended December 31, 2006 compared to $18.5 million for the year ended December 31, 2005, an increase of $14.0 million, or 76%. This increase primarily relates to (i) our acquisition of certain Oklahoma assets in August 2005 of $11.3 million and (ii) increased field personnel, field utility, regulatory, pipeline lease, chemical, repair and maintenance expenses of $2.7 million in our Texas segment, partially as a result of acquiring approximately 200 miles of pipelines during 2006.

Depreciation and Amortization. Depreciation and amortization totaled $32.0 million for the year ended December 31, 2006 compared with $17.1 million for the year ended December 31, 2005, an increase of $14.9 million, or 87%. This increase relates primarily to additional depreciation and amortization associated with acquisitions and capital expenditures made after December 31, 2005 and our acquisition of certain Oklahoma assets on August 1, 2005.

General and Administrative Expenses. General and administrative expenses totaled $26.5 million for the year ended December 31, 2006 compared with $18.2 million for the year ended December 31, 2005, an increase of $8.3 million, or 46%. The increase primarily relates to (i) expenses associated with the operations of our Oklahoma segment acquired in August 2005 of $2.6 million, (ii) expenses associated with additional personnel, consultants and office space and compensation adjustments of $3.2 million (excluding those expenses associated with our Oklahoma segment), (iii) costs of Sarbanes-Oxley compliance and accounting fees of $0.9 million and (iv) non-cash compensation expense related to the amortization of the fair value of restricted units and unit options issued to employees and directors of $0.6 million. Additionally, we experienced an increase of $1.0 million related to expenses associated with acquisition initiatives that were not consummated.

Interest Expense. Interest and other financing costs totaled $32.9 million for the year ended December 31, 2006 compared with $20.5 million for the year ended December 31, 2005. Interest expense related to our senior secured revolving credit facility totaled $8.8 million (net of $1.0 million of capitalized interest and settlements under our interest rate swaps) and $8.1 million for the years ended December 31, 2006 and 2005, respectively.

Interest on our Senior Notes totaled $16.5 million for the year ended December 31, 2006. Interest on our unsecured term loan and our term loan facility totaled $3.1 million for the year ended December 31, 2006. Interest on our term loan facility totaled $6.6 million for the year ended December 31, 2005. Amortization of debt issue costs totaled $4.5 million and $5.8 million for the years ended December 31, 2006 and 2005, respectively. Amortization of debt issue costs for the year ended December 31, 2006 included a one-time charge of $1.7 million related to the reduction of the commitment under our senior secured revolving credit facility from $350 million to $200 million and a one-time charge of $0.6 million related to the early termination of the unsecured term loan. Amortization of debt issue costs for the year ended December 31, 2005 included one-time charges of $1.6 million related to the early termination of credit facilities in existence prior to the senior secured revolving credit facility. Interest expense increased primarily as a result of increased borrowings under our credit agreements as a result of our acquisition of our Oklahoma segment on August 1, 2005 and the issuance of our Senior Notes in February 2006. Average borrowings under these credit arrangements were $373.2 million and $227.5 million with average interest rates of 8.3% and 7.6% for the years ended December 31, 2006 and 2005, respectively. Please read "— Liquidity and Capital Resources — Description of Our Indebtedness" for a detailed discussion of our senior secured revolving credit facility and our Senior Notes.

General Trends and Outlook

Our segment gross margins are influenced by the price of natural gas and by drilling activity in our operating regions. In our Oklahoma segment, increases in natural gas prices generally have a positive impact on our segment gross margins and, conversely, a reduction in natural gas prices negatively impacts our segment gross margins. Increases in natural gas prices generally have a negative impact on our Texas segment gross margins and, conversely, a reduction in natural gas prices positively impacts our Texas segment gross margins. On average, natural gas prices for the last half of 2007 trended upward as compared to natural gas prices for 2006. The profitability of our Rocky Mountains segment is not significantly affected by commodity prices because substantially all of its contractual arrangements are fixed-fee arrangements.

Volumes of natural gas on our pipelines also impact our segment gross margins. Increases in volumes gathered or transported positively impact our segment gross margins and conversely, reductions in volumes gathered or transported negatively impact our segment gross margins. Higher natural gas prices typically encourage drilling activity in our operating regions. On average, the volume of natural gas on our pipelines increased in 2007 as compared to 2006. We believe that natural gas prices will continue to fluctuate over the next twelve months but will remain at levels sufficient to support continued drilling activity.

Our Oklahoma and Texas segment gross margins are also influenced by the price of NGLs and the content of NGLs contained in natural gas delivered to our plants or that we deliver to third-party plants where we process natural gas. Increases in NGL prices have a positive impact on these segment gross margins and, conversely, a reduction in NGL prices negatively impacts these segment gross margins for each of our operating segments. On average, NGL prices for 2007 trended upward as compared to NGL prices for 2006. Average NGL prices for 2006 were higher than the full-year average price in 2005. We believe that NGL prices will continue to fluctuate in 2008, but at levels generally consistent with current levels. The content of NGLs in natural gas delivered to our plants or that we deliver to third-party plants where we process natural gas also impacts these gross margins. Increases in the content of NGLs in this natural gas positively impacts our Oklahoma and Texas segment gross margins if the price of NGLs exceeds the cost of the natural gas required to extract such NGLs. Conversely, reductions in the NGL content of this natural gas negatively impact our segment gross margins under such circumstances.

In addition to operating and maintenance expenses, general and administrative expenses and maintenance capital expenditures, our distributable cash flow is impacted by the interest expense we pay on our indebtedness. Currently, interest rates on substantially all of our borrowings outstanding under our senior secured revolving credit facility effectively are fixed as a result of interest rate hedges. Our borrowings in excess of currently hedged amounts bear interest at a rate that fluctuates based on reserve-adjusted interbank offered market rates. Increases in floating interest rates have a negative impact on our distributable cash flow and, conversely, decreases in floating interest rates have a positive impact on distributable cash flow. Interest rates for 2007 and 2008 have trended downward.

Impact of Inflation

Inflation in the United States has been relatively low in recent years in the economy as a whole. The midstream natural gas industry has experienced an increase in labor and materials costs during the year, although these increases did not have a material impact on our results of operations for the periods presented. Although the impact of inflation has not been significant in recent years, it is still a factor in the United States economy in general and specifically in the midstream natural gas industry and may further increase the cost to acquire or replace property, plant and equipment and may further increase the cost of labor and supplies and capital available to us. To the extent permitted by competition, regulation and our existing agreements, we may pass along increased costs to our customers in the form of higher fees.

Liquidity and Capital Resources

Cash generated from operations, borrowings under our senior secured revolving credit facility and funds from equity and debt offerings are our primary sources of liquidity. We believe that funds from these sources should be sufficient to meet both our short-term working capital requirements and our long-term capital expenditure requirements. Our ability to pay distributions to our unitholders, to fund planned capital expenditures and to make acquisitions will depend upon our future operating performance, and more broadly, on the availability of equity and debt financing, which will be affected by prevailing economic conditions in our industry and financial, business and other factors, some of which are beyond our control.

Off-Balance Sheet Arrangements. We had no off-balance sheet arrangements as of December 31, 2007.

Capital Requirements. The natural gas gathering, transmission, and processing businesses are capital-intensive, requiring significant investment to maintain and upgrade existing operations. Our capital requirements have consisted primarily of, and we anticipate will continue to be:

- maintenance capital expenditures, which are capital expenditures employed to replace partially or fully depreciated assets to maintain the existing operating capacity of our assets and to extend their useful lives, or other capital expenditures that are incurred in maintaining existing system volumes and related cash flows; and

- expansion capital expenditures such as those to acquire additional assets to grow our business, to expand and upgrade gathering systems, transmission capacity or processing plants and to construct or acquire new pipelines or processing plants.

Given our objective of growth through acquisitions, we anticipate that we will continue to invest significant amounts of capital to grow and acquire assets. We actively consider a variety of assets for potential acquisitions. For a discussion of the primary factors we consider in deciding whether to pursue a particular acquisition, please read "— Our Long-Term Growth Strategy — Acquisition Analysis."

During the year ended December 31, 2007, our capital expenditures totaled $893.4 million, consisting of $9.1 million of maintenance capital and $884.3 million of expansion capital. We funded our capital expenditures with funds from operations, borrowings under our senior secured revolving credit facility and the issuance of additional equity. Additional expansion capital expenditures were related to the acquisition and construction of small pipeline systems, purchasing compressors and constructing well interconnects to attach volumes in new areas. We expect to fund future capital expenditures with funds generated from our operations, borrowings under our senior secured revolving credit facility and the issuance of additional equity or debt as appropriate given market conditions. Based on our current scope of operations, we anticipate incurring approximately $11.0 million to $13.0 million of maintenance capital expenditures over the next 12 months.

Contractual Cash Obligations. A summary of our contractual cash obligations as of December 31, 2007, is as follows:

Type of Obligation	Payment Due by Period Total Obligation	Within 1 Year	2-3 Years	4-5 Years	More than 5 years
			(In thousands)		
Long-term debt	$ 630,000	$ —	$ —	$ —	$630,000
Interest(1)	316,806	46,095	92,191	88,611	89,909
Gathering and transportation firm commitments	161,222	20,630	35,774	32,780	72,038
Operating leases	7,260	3,322	2,906	1,032	—
Total contractual cash obligations(1)	$1,115,288	$70,047	$130,871	$122,423	$791,947

(1) These amounts exclude estimates of the effect of our interest rate swap contracts on our future interest obligations. As of December 31, 2007, the fair value of our interest rate swap contracts, which expire between July 2010 and October 2012, totaled $4.1 million.

In addition to our contractual obligations noted in the table above, we have both fixed and variable quantity contracts to purchase natural gas, which were executed in connection with our natural gas marketing activities. As of December 31, 2007, we had fixed contractual commitments to purchase 1,296,500 MMBtu of natural gas in January 2008. All of these contracts were based on index-related prices. Using these index-related prices at December 31, 2007, we had total commitments to purchase $8.9 million of natural gas under such agreements. Our contracts to purchase variable quantities of natural gas at index-related prices range from one month to the life of the dedicated production. During December 2007, we purchased 9,410,259 MMBtu of natural gas under such contracts.

For a discussion of our real property leases, please read Item 1, "Business — Office Facilities."

Cash Flows.

The following summarizes our cash flows for each of the three years ended December 31, 2007, as reported in the historical consolidated statements of cash flows found in Item 8 of this Annual Report.

	Year Ended December 31, 2007	2006	2005
		(In thousands)	
Net cash provided by operating activities	$ 128,218	$ 91,679	$ 280
Net cash used in investing activities	(727,052)	(70,291)	(491,708)
Net cash provided by (used in) financing activities	632,015	(7,201)	509,710
Net increase in cash and cash equivalents	33,181	14,187	18,282
Cash and cash equivalents at beginning of year	39,484	25,297	7,015
Cash and cash equivalents at end of year	$ 72,665	$ 39,484	$ 25,297

Operating Activities:

	Year Ended December 31,		
	2007	2006	2005
		(In thousands)	
Net income	$ 63,175	$ 65,114	$ 30,352
Depreciation and amortization	41,633	36,455	22,775
Equity in earnings from unconsolidated affiliates	(2,850)	(1,297)	(927)
Distributions from unconsolidated affiliates	3,706	—	—
Equity compensation and other	4,318	2,086	1,309
Cash used in working capital	18,236	(10,679)	(53,229)
Net cash provided by operating activities	$128,218	$ 91,679	$ 280

The overall increase of $36.5 million in operating cash flow for the year ended December 31, 2007 compared to the year ended December 31, 2006 was primarily the result of (i) increase in distributions from Webb Duval and Southern Dome, our unconsolidated affiliates, of $3.7 million, (ii) an increase in non-cash items of $5.9 million and (iii) increases in working capital components (exclusive of cash and cash equivalents) of $28.8 million offset by (iv) a decrease in net income of $1.9 million. The increase in the changes in working capital components (exclusive of cash and cash equivalents) was primarily the result of decreases in accounts receivable and prepaid items of $52.9 million offset by an increase in risk management assets of $1.3 million and increases in accounts payable and accrued liabilities of $80.4 million.

The overall increase of $91.4 million in operating cash flow for the year ended December 31, 2006 compared to the year ended December 31, 2005 was primarily the result of an increase in net income of $34.8 million, an increase in non-cash items of $14.1 million and an increase in the changes in working capital components (exclusive of cash and cash equivalents) of $42.5 million. This increase in the changes in working capital components (exclusive of cash and cash equivalents) was primarily the result of increases in accounts receivable and prepaid items of $31.7 million and risk management assets of $19.6 million and a decrease in accounts payable and accrued liabilities of $8.8 million.

We believe that we will continue to have adequate liquidity to fund future recurring operating and investing activities for the next 12 months. Our primary cash requirements consist of normal operating expenses, capital expenditures to sustain existing operations and revenue generating expenditures, interest payments on our senior secured revolving credit facility and Senior Notes, distributions to our unitholders and acquisitions of new assets or businesses. Short-term cash requirements, such as operating expenses, capital expenditures to sustain existing operations and quarterly distributions to our unitholders, are expected to be funded through operating cash flows. Long-term cash requirements for expansion projects and acquisitions are expected to be funded by several sources, including cash flows from operating activities, borrowings under our senior secured revolving credit facility and the issuance of additional equity and debt securities, as appropriate. Our ability to complete future debt and equity offerings and the timing of any such offerings will depend on various factors, including prevailing market conditions, interest rates, our financial condition and our credit ratings at the time.

Investing Activities. Net cash used in investing activities was $727.1 million for the year ended December 31, 2007. Investing activities for 2007 included (i) $641.1 million of capital expenditures related to the Cantera and Cimmarron acquisitions, (ii) $84.3 million of capital expenditures related to bolt-on pipeline acquisitions, the expansion and modification of our Paden plant and progress payments for the purchase of compression and (iii) $1.7 million of investment in Bighorn after the closing of the acquisition in October 2007.

Net cash used in investing activities was $70.3 million for the year ended December 31, 2006. Investing activities for 2006 include costs primarily related to (i) $59.9 million of capital expenditures for several bolt-on pipeline acquisitions, costs related to the construction of an 11-mile pipeline to our Provident City system, progress payments for the purchase of compressor units, the installation of an additional amine treater and a modification of an existing amine treater at our Houston Central plant, the addition and installation of a refrigeration unit and condensate stabilizer at the Paden plant in Oklahoma, the construction of an 8-mile pipeline between two compressor stations in our Oklahoma area and the acquisition of rights-of-way and (ii) $10.4 million investment in Southern Dome, our unconsolidated affiliate, for the construction of a processing plant and residue pipelines that began operations in late April 2006.

Net cash used in investing activities was $491.7 million for the year ended December 31, 2005. Capital expenditures for 2005 include costs related to the acquisition of our Oklahoma segment and several small pipeline systems and the completion of well connections.

Financing Activities. Net cash provided by financing activities totaled $632.0 million during the year ended December 31, 2007 and included (i) borrowings under our senior secured revolving credit facility of $538.0 million, (ii) issuance of additional Senior Notes of $125.8 million, (iii) proceeds from our private placements of common units of $157.1 million and Class E units of $177.9 million in October 2007 in connection with the Cantera acquisition, (iv) capital contributions of $10.0 million from our pre-IPO Investors to fulfill their G&A expense reimbursement obligations and (v) proceeds from the exercise of unit options of $1.8 million, offset by (a) repayments under our debt arrangements of $289.5 million, (b) distributions to our unitholders of $73.6 million, (c) deferred financing costs of $10.7 million and (d) equity offering costs of $4.8 million related to our private placements of equity during 2007.

Net cash used in financing activities totaled $7.7 million during the year ended December 31, 2006 and included (i) net proceeds from our follow-on public offering of common units in December 2006 of $161.8 million, (ii) net proceeds from our private placement of common units of $24.4 million in January 2006, (iii) capital contributions of $4.6 million from our pre-IPO investors and (iv) proceeds from the exercise of unit options of $0.4 million, offset by (a) net repayments under our debt arrangements of $144.9 million, (b) distributions to our unitholders of $47.0 million and (c) deferred financing costs of $7.0 million.

Net cash provided by financing activities totaled $509.7 million during the year ended December 31, 2005 and included (i) net borrowings under our credit facilities of $341.0 million, (ii) net proceeds from the private placement of common units and Class B units of $198.9 million in August 2005 and December 2005 and (iii) capital contributions of $4.2 million from our pre-IPO investors and from the exercise of unit options, offset by (a) distributions to our unitholders of $23.4 million, (b) deferred financing costs of $9.8 million and (c) $1.2 million of payments under short-term financing arrangements.

Cash Distributions and Reserves. For a discussion of our cash distributions and reserves, please read Item 5 “Market for Registrant’s Common Equity, Related Unitholder Matters and Issuer Purchases of Equity Securities” of this Annual Report.

Description of Our Indebtedness

As of December 31, 2007 and 2006, our aggregate outstanding indebtedness totaled $630 million and $255 million, respectively.

Credit Ratings. Moody’s Investors Service has assigned a Corporate Family Rating to us of B1 with a positive outlook, a B2 rating for our Senior Notes and a Speculative Grade Liquidity rating of SGL-3. Standard & Poor’s Ratings Services has assigned a Corporate Credit Rating of BB- with a positive outlook and a B+ rating for our Senior Notes.

Senior Secured Revolving Credit Facility. Our senior secured revolving credit facility (the “Credit Facility”) is provided by Bank of America, N.A., as Administrative Agent, and a group of financial institutions, as lenders, and was established in August 2005. Our obligations under the Credit Facility are secured by first priority liens on substantially all of our assets and substantially all of the assets of our wholly owned subsidiaries (except for certain equity interests we acquired through our acquisitions of Cantera and Cimmarron), all of which are party to the Credit Facility as guarantors. Our less-than-wholly owned subsidiaries have not pledged their assets to secure the Credit Facility and do not guarantee obligations under the Credit Facility.

In January 2007, we modified the Credit Facility to, among others things, extend its maturity date to April 15, 2012, revise the interest rate provisions and the commitment fee provisions, increase the maximum ratio of our total debt to EBITDA (as defined under the Credit Facility) permitted under the Credit Facility and eliminate the following: (i) the limitation on our use of borrowings under the Credit Facility to make certain types of capital expenditures, (ii) the maximum consolidated fixed charge coverage ratio covenant and (iii) the maximum consolidated senior leverage ratio covenant.

On October 19, 2007, in connection with the Cantera acquisition, we further amended our Credit Facility to increase the aggregate borrowing capacity under the Credit Facility from $200 million to $550 million, extend the maturity date to October 18, 2012, revise the interest rate and commitment fee provisions, revise certain covenants to accommodate our obligations as managing member of each of Bighorn and Fort Union, and to accommodate previously existing obligations of each entity, provide for swing line borrowings in addition to committed borrowings, revise the minimum consolidated interest coverage ratio from 3.0:1 to 2.5:1, and increase the sublimit for the issuance of standby letters of credit from $25 million to $50 million.

Future borrowings under the Credit Facility are available for acquisitions, capital expenditures, working capital and general corporate purposes. The Credit Facility is available to be drawn on and repaid without restriction so long as we are in compliance with the terms of the Credit Facility, including certain financial covenants.

Annual interest under the Credit Facility is determined, at our election, by reference to (i) the British Bankers Association LIBOR rate, or LIBOR, plus an applicable margin ranging from 1.25% to 2.50%, or (ii) the higher of the federal funds rate plus 0.5% or the prime rate plus, in either case, an applicable margin ranging from 0.25% to 1.50%. Interest is payable quarterly for prime rate loans and at the applicable maturity date for LIBOR loans, except that if the interest period for a LIBOR loan is six months, interest will be paid at the end of each three-month period. The effective average interest rate on borrowings under the Credit Facility for the years ended December 31, 2007, 2006 and 2005 was 6.9%, 7.4% and 6.15%, respectively, and the quarterly commitment fee on the unused portion of the Credit Facility for those periods, respectively, was 0.20%, 0.25% and 0.25%.

The Credit Facility contains various covenants that, subject to exceptions, limit our and subsidiary guarantors' ability to grant liens; make loans and investments; make distributions other than from available cash (as defined in our limited liability company agreement); merge or consolidate with or into a third party; or engage in certain asset dispositions, including a sale of all or substantially all of our assets. Additionally, the Credit Facility limits our and our subsidiary guarantors' ability to incur additional indebtedness, subject to exceptions, including (i) purchase money indebtedness and indebtedness related to capital or synthetic leases, (ii) unsecured indebtedness qualifying as subordinated debt and (iii) certain privately placed or public term unsecured indebtedness.

The Credit Facility also contains financial covenants, which, among other things, require us and our subsidiary guarantors, on a consolidated basis, to maintain specified ratios or conditions as follows:

- EBITDA to interest expense of not less than 2.5 to 1.0; and
- total debt to EBITDA of not more than 5.0 to 1.0 (with no future reductions) with the option to increase the total debt to EBITDA ratio to not more than 5.5 to 1.0 for a period of up to nine months following an acquisition or a series of acquisitions totaling $50 million in a 12-month period (subject to an increased applicable interest rate margin and commitment fee rate).

Based on the total debt to EBITDA ratio calculated as of December 31, 2007 (utilizing trailing four quarters' EBITDA as defined under the Credit Facility), we have approximately $270.0 million of unused capacity under the Credit Facility.

If an event of default exists under the Credit Facility, the lenders may accelerate the maturity of the obligations outstanding under the Credit Facility and exercise other rights and remedies. Each of the following would be an event of default:

- failure to pay any principal when due or any interest, fees or other amount within specified grace periods;
- failure to perform or otherwise comply with the covenants in the credit agreement or other loan documents, subject to certain grace periods in some cases;
- default on the payment of any other indebtedness in excess of $5 million, or in the performance of any obligation or condition with respect to such indebtedness, beyond the applicable grace period if the effect of the default is to permit or cause the acceleration of the indebtedness;

- bankruptcy or insolvency events involving us or our subsidiaries;
- if Bighorn or Fort Union is unable to make a quarterly distribution to its members, our inability to demonstrate compliance with financial covenants within a specified period;
- the entry of, and failure to pay, one or more adverse judgments in excess of $5 million upon which enforcement proceedings are brought or are not stayed pending appeal; and
- a change of control (as defined in the Credit Facility).

Our management believes that we are in compliance with the covenants under the Credit Facility as of December 31, 2007.

Senior Notes. In February 2006, we issued $225 million in aggregate principal amount of our 8⅛% senior notes due 2016 (the "Senior Notes"). In November 2007, we issued an additional $125 million in aggregate principal amount of our Senior Notes. The additional Senior Notes were offered under our effective shelf registration statement and constitute an additional issuance under the indenture governing the Senior Notes. We used the net proceeds, after deducting initial purchaser discounts and offering costs of $1.3 million, to reduce the balance outstanding under our Credit Facility.

The Senior Notes represent our senior unsecured obligations and rank equally in right of payment with all our other present and future senior indebtedness. The Senior Notes are effectively subordinated to all of our secured indebtedness to the extent of the value of the assets securing the indebtedness, and to all existing and future indebtedness and liabilities, including trade payables, of our non-guarantor subsidiaries (other than indebtedness and other liabilities owed to us, if any). The Senior Notes rank senior in right of payment to all of our future subordinated indebtedness.

The Senior Notes are jointly and severally guaranteed by all of our wholly owned subsidiaries (other than Copano Energy Finance Corp., the co-issuer of the Senior Notes). The subsidiary guarantees rank equally in right of payment with all of the existing and future senior indebtedness of our guarantor subsidiaries, including their guarantees of our other senior indebtedness. The subsidiary guarantees are effectively subordinated to all existing and future secured indebtedness of our subsidiary guarantors (including under our Credit Facility) to the extent of the value of the assets securing that indebtedness, and to all existing and future indebtedness and other liabilities, including trade payables, of any non-guarantor subsidiaries (other than indebtedness and other liabilities owed to our guarantor subsidiaries). The subsidiary guarantees rank senior in right of payment to any future subordinated indebtedness of our guarantor subsidiaries.

Before March 1, 2009, we may, at any time or from time to time, use net proceeds from a public or private equity offering to redeem up to 35% of the aggregate principal amount of the Senior Notes at a redemption price of 108.125% of the principal amount of the Senior Notes, plus any accrued and unpaid interest, so long as at least 65% of the aggregate principal amount of the Senior Notes remains outstanding after such redemption and the redemption occurs within 120 days of the date of the closing of such equity offering.

The Senior Notes are redeemable in whole or in part, at our option, at any time on or after March 1, 2011 and at the redemption prices in the table below, together with any accrued and unpaid interest to the date of redemption.

Year	Percentage
2011	104.0625%
2012	102.7083%
2013	101.3542%
2014 and thereafter	100.0000%

Prior to March 1, 2011, we may redeem the Senior Notes, in whole or in part, at a "make-whole" redemption price together with any accrued and unpaid interest to the date of the redemption.

The indenture governing the Senior Notes includes covenants that limit our and our subsidiary guarantors' ability to, among other things:

- sell assets;

- pay distributions on, redeem or repurchase our units, or redeem or repurchase our subordinated debt;
- make investments;
- incur or guarantee additional indebtedness or issue preferred units;
- create or incur liens;
- enter into agreements that restrict distributions or other payments from our restricted subsidiaries to us;
- consolidate, merge or transfer all or substantially all of our assets;
- engage in transactions with affiliates;
- create unrestricted subsidiaries; and
- enter into sale and leaseback transactions.

These covenants are subject to customary exceptions and qualifications. Additionally, if the Senior Notes achieve an investment grade rating from each of Moody's Investors Service and Standard & Poor's Ratings Services, many of these covenants will terminate. Our management believes that we are in compliance with the covenants under the Senior Notes indenture as of December 31, 2007.

Recent Accounting Pronouncements

Accounting for Uncertainty in Income Taxes. In June 2006, the FASB issued FASB Interpretation No. 48 ("FIN 48"), *"Accounting for Uncertainty in Income Taxes-An Interpretation of FASB Statement No. 109."* FIN 48 clarifies the accounting for uncertainties in income taxes recognized in an enterprise's financial statements in accordance with SFAS No. 109, *"Accounting for Income Taxes"*, by prescribing thresholds and attributes for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. If a tax position is "more likely than not" to be sustained upon examination, then an enterprise would be required to recognize in its financial statements the largest amount of benefit that is greater than 50% likely of being realized upon ultimate settlement. The provisions of FIN 48 will be effective as of the beginning of our 2007 fiscal year, with any cumulative effect of the change in accounting principle recorded as an adjustment to opening retained earnings. The provisions of FIN 48 became effective as of the beginning of our 2007 fiscal year and our adoption of FIN 48 did not have a material impact on our consolidated financial position.

Business Combinations. In December 2007, the FASB issued SFAS No. 141 (Revised), "*Business Combinations"* ("SFAS No. 141(R)"). We have not completed our assessment of the impact, if any, from our adoption of SFAS No. 141(R). SFAS No. 141(R) is effective for fiscal years beginning after November 15, 2008.

Fair Value Measurements. In September 2006, the FASB issued SFAS No. 157, *"Fair Value Measurements."* SFAS No. 157 establishes a framework for measuring fair values under generally accepted accounting principles and applies to other pronouncements that either permit or require fair value measurement, including SFAS No. 133. The standard is effective for reporting periods beginning after November 15, 2007. We adopted this statement beginning January 1, 2008 and the adoption did not have material impact on our consolidated cash flows, results of operations or financial position.

Fair Value Option for Financial Assets and Financial Liabilities. In February 2007, the FASB issued SFAS No. 159, *"The Fair Value Option for Financial Assets and Financial Liabilities,"* which permits entities to choose to measure many financial instruments and certain other items at fair value. SFAS No. 159 is effective for us as of January 1, 2008 and will have no impact on amounts presented for periods prior to the effective date. We adopted this statement beginning January 1, 2008, and the adoption did not have a material impact on our consolidated cash flows, results of operations or financial position. We have chosen not to measure items subject to SFAS No. 159 at fair value.

Non-Controlling Interests in Consolidated Financial Statements — an Amendment of ARB No. 51. In December 2007, the FASB issued SFAS No. 160, "*Non-Controlling Interests in Consolidated Financial Statements — an Amendment of ARB No. 51"* (SFAS No. 160). We are currently evaluating the impact that

SFAS No. 160 might have on our financial statements upon adoption. SFAS No. 160 is effective for fiscal years beginning after November 15, 2008.

Critical Accounting Policies and Estimates

The selection and application of accounting policies is an important process that has developed as our business activities have evolved and as the accounting rules have developed. Accounting rules generally do not involve a selection among alternatives, but involve an implementation and interpretation of existing rules, and the use of judgment applied to the specific set of circumstances existing in our business. We make every effort to properly comply with all applicable rules on or before their adoption, and we believe the proper implementation and consistent application of the accounting rules are critical. For further details on our accounting policies, please read Notes 2 and 3 to the Consolidated Financial Statements contained in Item 8 in this Annual Report.

Impairment of Long-Lived Assets. In accordance with SFAS No. 144, *"Accounting for the Impairment or Disposal of Long-Lived Assets,"* we evaluate whether long-lived assets, including related intangibles, have been impaired when events or changes in circumstances indicate, in management's judgment, that the carrying value of such assets may not be recoverable. For such long-lived assets, an impairment exists when its carrying value exceeds the sum of management's estimate of the undiscounted future cash flows expected to result from the use and eventual disposition of the asset. If the carrying value of the long-lived asset is not recoverable based on these estimated future undiscounted cash flows, the impairment loss is measured as the excess of the asset's carrying value over its fair value, such that the asset's carrying value is adjusted to its estimated fair value. For assets identified to be disposed of in the future, the carrying value of these assets is compared to the estimated fair value less the cost to sell to determine if impairment is required. Until the assets are disposed of, an estimate of the fair value is recalculated when related events or circumstances change.

When determining whether impairment of one of our long-lived assets has occurred, we must estimate the undiscounted cash flows attributable to the asset or asset group. Our estimate of cash flows is based on assumptions regarding the asset and future NGL product and natural gas prices. The amount of reserves and drilling activity are dependent in part on natural gas prices. Projections of gas volumes and future commodity prices are inherently subjective and contingent upon a number of variable factors, including but not limited to:

- changes in general economic conditions in regions in which our assets are located;
- the availability and prices of raw natural gas supply;
- improvements in exploration and production technology;
- our ability to negotiate favorable sales agreements;
- our dependence on certain significant customers, producers, gatherers, and transporters of natural gas; and
- competition from other midstream service providers, including major energy companies.

Any significant variance in any of the above assumptions or factors could materially affect our cash flows, which could require us to record an impairment of an asset.

Investments in Unconsolidated Affiliates — Equity Method of Accounting. Although we own a 62.5% partnership interest in Webb Duval, a majority interest in Southern Dome and a 51% member interest in Bighorn and we operate all the pipelines owned by these entities, we account for these investments using the equity method of accounting. For unconsolidated affiliates that we own a greater than 50% interest in, we use the equity method of accounting because the minority general partners or members have substantive participating rights with respect to the management of these entities. We also use the equity method of accounting with respect to our 37.04% member interest in Fort Union.

Revenue Recognition. Our natural gas, NGL and crude oil revenue is recognized in the period when the physical product is delivered to the customer at contractually agreed-upon pricing. Transportation, gathering, compression and processing-related revenues are recognized in the period when the service is provided.

Forward-Looking Statements

This Annual Report contains certain "forward-looking statements" within the meaning of the federal securities laws. All statements, other than statements of historical fact included in this Annual Report, including, but not limited to, those under "— Our Results of Operation" and "— Liquidity and Capital Resources" are forward-looking statements. Statements included in this Annual Report that are not historical facts, but that address activities, events or developments that we expect or anticipate will or may occur in the future, including things such as references to future goals or intentions or other such references are forward-looking statements. These statements can be identified by the use of forward-looking terminology including "may," "believe," "expect," "anticipate," "estimate," "continue," or similar words. These statements include statements related to plans for growth of the business, future capital expenditures and competitive strengths and goals. We make these statements based on our past experience and our perception of historical trends, current conditions and expected future developments as well as other considerations we believe are appropriate under the circumstances. Whether actual results and developments in the future will conform to our expectations is subject to numerous risks and uncertainties, many of which are beyond our control. Therefore, actual outcomes and results could materially differ from what is expressed, implied or forecast in these statements. Any differences could be caused by a number of factors, including, but not limited to:

- our ability to successfully integrate any acquired assets or operations;
- the volatility of prices and market demand for natural gas and NGLs;
- our ability to continue to obtain new sources of natural gas supply;
- the ability of key producers to continue to drill and successfully complete and attach new natural gas supplies;
- our ability to retain our key customers;
- general economic conditions;
- the effects of government regulations and policies; and
- other financial, operational and legal risks and uncertainties detailed from time to time in our filings with the SEC.

Cautionary statements identifying important factors that could cause actual results to differ materially from our expectations are set forth in this Annual Report, including without limitation in conjunction with the forward-looking statements that are referred to above. When considering forward-looking statements, you should keep in mind the risk factors and other cautionary statements set forth in this Annual Report under Item 1A, "— Risk Factors." All forward-looking statements included in this Annual Report and all subsequent written or oral forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by these cautionary statements. The forward-looking statements speak only as of the date made, other than as required by law, and we undertake no obligation to publicly update or revise any forward-looking statements, other than as required by law, whether as a result of new information, future events or otherwise.

Item 7A. *Quantitative and Qualitative Disclosures about Market Risk*

Market risk is the risk of loss arising from adverse changes in market rates and prices. We are exposed to market risks, including changes in commodity prices and interest rates. We may use financial instruments such as options, swaps and other derivatives to mitigate the effects of the identified risks. In general, we attempt to hedge risks related to the variability of future earnings and cash flows resulting from changes in applicable commodity prices or interest rates so that we can maintain cash flows sufficient to meet debt service, required capital expenditures, distribution objectives and similar requirements. Our risk management policy prohibits the use of derivative instruments for speculative purposes.

Commodity Price Risk. NGL and natural gas prices are volatile and are impacted by changes in fundamental supply and demand, as well as market uncertainty and a variety of additional factors that are beyond our control. Our profitability is affected by prevailing commodity prices primarily as a result of two components of our business:

(i) processing or conditioning at our processing plants or third-party processing plants and (ii) purchasing and selling volumes of natural gas at index-related prices. The following discussion describes our commodity price risks as of December 31, 2007.

A majority of the processing contracts in our Oklahoma segment are percentage-of-proceeds arrangements. Under these arrangements, we generally receive and process natural gas on behalf of producers and sell the resulting residue gas and NGL volumes. As payment, we retain an agreed-upon percentage of the sales proceeds, which results in effectively long positions in both natural gas and NGLs. Accordingly, our revenues and gross margins increase as natural gas and NGL prices increase and revenues and gross margins decrease as natural gas and NGL prices decrease. Our Oklahoma segment also has fixed fee-contracts and percentage-of-index contracts.

Our Texas pipeline systems purchase natural gas for transportation and resale and also transport and provide other services on a fee-for-service basis. A significant portion of the margins we realize from purchasing and reselling the natural gas is based on a percentage of a stated index price. Accordingly, these margins decrease in periods of low natural gas prices and increase during periods of high natural gas prices. Although fees for natural gas that we transport on our pipeline systems for the accounts of others are primarily fixed, our Texas contracts also include a percentage-of-index component in a number of cases. A significant portion of the gas processed by our Texas segment is processed under keep-whole with fee arrangements. Under these arrangements, increases in NGL prices or decreases in natural gas prices generally have a positive impact on our gross margins and, conversely, a reduction in NGL prices or increases in natural gas prices generally negatively impact our gross margins. However, the ability of our Houston Central plant to operate in a conditioning mode allows us to reduce our Texas processing operations' exposure to commodity prices. Please read Item 1, "Business — Our Operations — Texas — Houston Central Systems and Processing Plant" for a discussion of our Texas segment's conditioning capability.

The profitability of our Rocky Mountains segment is not significantly affected by the level of commodity prices. Substantially all of our Rocky Mountains contractual arrangements as well as the contractual arrangements of Fort Union and Bighorn are fixed-fee arrangements pursuant to which the gathering fee income represents an agreed rate per unit of throughput. The revenue we earn as a result of these arrangements is directly related to the volume of natural gas that flows through these systems and is not directly affected by commodity prices. To the extent a sustained decline in commodity prices results in a decline in volumes, however, our revenues under these arrangements would be reduced.

In order to calculate the sensitivity of our total segment gross margin to commodity price changes, we adjusted our operating models for actual commodity prices, plant recovery rates and volumes. We have calculated that a $0.01 per gallon change in either direction of NGL prices would have resulted in a corresponding change of approximately $1.3 million to our total segment gross margin for the year ended December 31, 2007. We also calculated that a $0.10 per MMBtu increase in the price of natural gas would have resulted in approximately a $1.2 million decrease to our total segment gross margin, and vice versa, for the year ended December 31, 2007. These relationships are not necessarily linear. Although our sensitivity analysis takes into account our hedge portfolio, , it does not fully reflect the effects of our hedging program due to the prices received for natural gas and NGLs during the year ended December 31, 2007. If actual prices were to fall below the strike prices of our hedges, sensitivity to the change in commodity prices would be reduced. Additionally, if processing margins are negative, we can operate our Houston Central plant in a conditioning mode so that additional increases in natural gas prices would have a positive impact to our total segment gross margin.

Although we seek to maintain a position that is substantially balanced between purchases and sales for future delivery obligations, from time to time, we experience imbalances between our natural gas purchases and sales. For example, a producer could fail to deliver or deliver in excess of contracted volumes, or a consumer could take more or less than contracted volumes. To the extent our purchases and sales of natural gas are not balanced, we face increased exposure to commodity prices with respect to the imbalance.

Commodity Price Hedging Activities. We seek to mitigate the price risk of natural gas and NGLs through the use of commodity derivative instruments. These activities are governed by our risk management policy, which, as amended in November 2007, allows our management to:

- purchase put options or "put spreads" (purchase of a put and a sale of a put at a lower strike price) on WTI crude oil to hedge natural gas liquids produced or condensate collected by us or an entity or asset to be acquired by us if a binding purchase and sale agreement has been executed (a "Pending Acquisition");
- purchase put or call options, enter into collars (purchase of a put together with the sale of a call) or "call or put spreads" ((i) purchase of a call and a sale of a call at a higher strike price or (ii) purchase of a put and a sale of a put at a lower strike price) and/or sell fixed for floating swaps on natural gas at Henry Hub, HSC or other highly liquid points relevant to our operations or a Pending Acquisition;
- purchase put options, enter into collars or "put spreads" (purchase of a put and a sale of a put at a lower strike price) and/or sell fixed for floating swaps on NGLs to which we, or a Pending Acquisition, has direct price exposure, priced at Mt. Belvieu or Conway; and
- purchase put options and collars and/or sell fixed for floating swaps on the "fractionation spread" or the "processing margin spread" for any processing plant relevant to our operations or a Pending Acquisition.

Our policy also limits the maturity and notional amounts of our derivatives transactions and requires that:

- Maturities with respect to the purchase of any crude oil, natural gas, NGLs, fractionation spread or processing margin spread hedge instruments must be limited to five years from the date of the transaction;
- Through December 31, 2008, notional volume must not exceed the projected requirements or output, as applicable, for the hedged period with respect to (i) the purchase of crude oil or NGL put options, (ii) the purchase of natural gas put or call options, (iii) the purchase of fractionation spread or processing margin spread put options or (iv) the entry into any crude oil, natural gas or NGL spread options permitted by the policy;
- After December 31, 2008, notional volume must not exceed 80% of the projected requirements or output, as applicable, for the hedged period with respect to (i) the purchase of crude oil or NGLs put options, (ii) the purchase of natural gas put or call options, (iii) the purchase of fractionation spread or processing margin spread put options or (iv) the entry into any crude oil, natural gas or NGL spread options; and
- The aggregate volumetric exposure associated with swaps, collars and written calls relating to any product must not exceed 50% of the aggregate hedged position with respect to such product.

Our policy of limiting swaps as a percentage of our overall hedge positions is intended to avoid risk associated with potential fluctuations in output volumes that may result from conditioning elections or other operational circumstances.

Our risk management policy requires derivative transactions to take place either on the New York Mercantile Exchange ("NYMEX") through a clearing member firm or with over-the-counter counterparties with investment grade ratings from both Moody's Investors Service and Standard & Poor's Ratings Services with complete industry standard contractual documentation. Under this documentation, the payment obligations in connection with our swap transactions are secured by a first priority lien in the collateral securing our senior secured indebtedness that ranks equal in right of payment with liens granted in favor of our senior secured lenders. As long as this first priority lien is in effect, we will have no obligation to post cash, letters of credit, or other additional collateral to secure these hedges at any time even if our counterparty's exposure to our credit increases over the term of the hedge as a result of higher commodity prices or because there has been a change in our creditworthiness.

We will seek, whenever possible, to enter into hedge transactions that meet the requirements for effective hedges as outlined in SFAS No. 133.

Oklahoma Segment. Natural gas for our Oklahoma segment is hedged using the CenterPoint East index, the principal index used to price the underlying commodity. With the exception of condensate, NGLs are contractually priced using the Conway index but since there is an extremely limited forward market for Conway, we use

Mt. Belvieu hedge instruments instead. While this creates the potential for basis risk, statistical analysis reveals that the two indices have been historically highly correlated.

Texas Segment. With the exception of condensate and a portion of our natural gasoline production, NGLs are hedged using the Mt. Belvieu index, the same index used to price the underlying commodities. We use natural gas call spread options to hedge a portion of our net operational short position in natural gas when we operate in a processing mode at our Houston Central plant. The call spread options are based on the HSC index, the same index used to price the underlying commodity. We do not hedge against potential declines in the price of natural gas for the Texas segment because our natural gas position is neutral to short due to our contractual arrangements and the ability of the Houston Central plant to switch between full recovery and conditioning mode.

Rocky Mountains Segment. Since the profitability of our Rocky Mountains segment is not significantly affected by the level of commodity prices, this segment has no outstanding transactions to hedge commodity price risk.

The following table summarizes our commodity hedge portfolio as of December 31, 2007 (all hedges are settled monthly):

Purchased CenterPoint East Natural Gas Puts

	Put Strike (Per MMBtu)	Put Volumes (MMBtu/d)	Fair Value
2008	$7.75	5,000	$2,080,000
2009	$6.95	5,000	$1,205,000

Purchased HSC Index Natural Gas Call Spreads

	Call Strike (Per MMBtu)		Call Volumes (MMBtu/d)	Fair Value
	Bought	Sold		
2008	$8.15	$10.00	9,400	$1,172,000
2009	$7.75	$10.00	8,000	$2,224,000
2010	$7.35	$10.00	7,100	$2,441,000
2011	$6.95	$10.00	7,100	$2,839,000

Purchased Purity Ethane Puts and Entered into Swaps as Listed Below:

	Put			Swap		
	Strike (per gallon)	Volumes (Bbls/d)	Fair Value	Price (per gallon)	Volumes (Bbls/d)	Fair Value
2008	$0.5700	607	$ —	$0.5650	607	$(4,674,000)
2008	$0.6250	2,900	$ 1,000	$0.6525	1,300	$(8,302,000)
2009	$0.5900	2,200	$ 8,000	$0.6025	1,100	$(6,536,000)
2010	$0.5550	1,600	$ 9,000	$0.5700	500	$(2,851,000)
2011	$0.5300	1,700	$10,000	$0.5450	500	$(2,866,000)

Purchased TET Propane Puts and Entered into Swaps as Listed Below:

	Put			Swap		
	Strike (per gallon)	Volumes (Bbls/d)	Fair Value	Price (per gallon)	Volumes (Bbls/d)	Fair Value
2008	$0.8360	2,594	$ 1,000	$0.8700	745	$(7,453,000)
2008	$0.8975	1,100	$ 2,000			
2008	$1.0500	396	$ 9,000	$ —	—	$ —
2009	$0.8725	2,200	$ 60,000			
2009	$0.9650	1,000	$ 81,000	$1.0275	1,000	$(6,184,000)
2010	$0.8500	1,100	$ 65,000			
2010	$0.9460	700	$107,000	$0.9925	700	$(4,106,000)
2011	$0.8265	1,100	$ 83,000			
2011	$0.9340	700	$139,000	$0.9750	700	$(4,041,000)

Purchased Non-TET Isobutane Puts and Entered into Swaps as Listed Below:

	Put			Swap		
	Strike (per gallon)	Volumes (Bbls/d)	Fair Value	Price (per gallon)	Volumes (Bbls/d)	Fair Value
2008	$0.9900	622	$ —	$1.0450	92	$(1,100,000)
2008	$1.0900	250	$ —			
2009	$1.0600	450	$10,000			
2009	$1.1600	100	$ 6,000	$1.2425	100	$ (733,000)
2010	$1.0350	300	$14,000			
2010	$1.1145	100	$10,000	$1.2025	100	$ (699,000)
2011	$1.0205	300	$20,000			
2011	$1.1100	100	$14,000	$1.1800	100	$ (691,000)

Purchased Non-TET Normal-Butane Puts and Entered into Swaps as Listed Below:

	Put			Swap		
	Strike (per gallon)	Volumes (Bbls/d)	Fair Value	Price (per gallon)	Volumes (Bbls/d)	Fair Value
2008	$0.9875	810	$ —	$1.0400	271	$(3,112,000)
2008	$1.0800	300	$ —			
2009	$1.0525	700	$3,000			
2009	$1.1400	400	$6,000	$1.2275	400	$(2,752,000)
2010	$1.0300	300	$3,000			
2010	$1.1000	200	$5,000	$1.1850	200	$(1,313,000)
2011	$1.0205	300	$4,000			
2011	$1.0850	200	$6,000	$1.1700	200	$(1,280,000)

Purchased Non-TET Natural Gasoline Puts and Entered into Swaps

	Put			Swap		
	Strike (per gallon)	Volumes (Bbls/d)	Fair Value	Price (per gallon)	Volumes (Bbls/d)	Fair Value
2008	$1.4850	300	$ 4,000	$1.5850	300	$(2,170,000)
2009	$1.4400	200	$18,000	$1.5400	200	$(1,219,000)
2010	$1.4080	300	$42,000	$ —	—	$ —
2011	$1.4100	300	$56,000	$ —	—	$ —

Purchased WTI Crude Oil Puts as Listed Below:

	Put Strike (per barrel)	Put Volumes (Bbls/d)	Fair Value
2008	$55.00	1,000	$ 6,000
2008	$60.00	700	$ 13,000
2009	$55.00	1,000	$ 89,000
2009	$60.00	500	$101,000
2010	$55.00	1,000	$214,000
2010	$60.00	400	$166,000
2011	$55.00	1,000	$317,000
2011	$60.00	400	$225,000

In January 2008, we purchased puts for ethane, propane, iso-butane, normal butane and West Texas Intermediate crude oil at strike price reflecting current market conditions, and divested previously acquired put options on these products at lower strike prices. These transactions were conducted through two investment grade counterparties in accordance with our risk management policy and were designated as cash flow hedges to mitigate the impact of increases in NGL prices. Our net costs for these transactions were approximately $15.6 million.

Interest Rates. Our interest rate exposure results from variable rate borrowings under our debt agreements. We manage a portion of our interest rate exposure by utilizing interest rate swaps, which allow us to convert a portion of variable rate debt into fixed rate debt. These activities are governed by our risk management policy, which limits the maturity and notional amounts of our interest rate swaps as well as restricts counterparties to certain lenders under our Credit Facility.

As of December 31, 2007, we were exposed to changes in interest rates as a result of the indebtedness outstanding under our Credit Facility of $280 million, of which $160 million was hedged with interest rate swaps to convert our floating interest rate to a fixed rate of 5.965%. Our Credit Facility had an average floating interest rate of 6.05% as of December 31, 2007 and a 1% increase in interest rates on the amount of debt in excess of the $160 million that was hedged would result in an increase in interest expense and a corresponding decrease in net income of approximately $1.2 million annually.

In January 2008, we entered into two new interest rate swap agreements with a notional amount of $50 million under which we exchanged the payment of variable rate interest on a portion of the principal outstanding under the Credit Facility for fixed rate interest. Under these agreements, we pay the counterparty the fixed interest rate of approximately 3.23% monthly and receive back from the counterparty a variable interest rate based on three-month LIBOR rates. These interest rate swaps cover the period from February 2008 through October 2012 and the settlement amounts will be recognized as either an increase or decrease in interest expense.

Risk Management Oversight. Our Risk Management Committee is responsible for our compliance with our risk management policy and is comprised of our Chief Executive Officer, Chief Operating Officer, Chief Financial Officer, General Counsel and the President of any operating subsidiary. The Audit Committee of our Board of Directors monitors the implementation of our policy and we have engaged an independent firm to provide additional oversight.

Credit Risk. We are diligent in attempting to ensure that we provide credit to only credit-worthy customers. However, our purchase and resale of natural gas exposes us to significant credit risk, as our margin on any sale is generally a very small percentage of the total sale price. Therefore, a credit loss could be very large relative to our overall profitability. For the year ended December 31, 2007, Enterprise Products Operating, L.P. (20%), ONEOK Energy Services (16%), ONEOK Hydrocarbons, L.P. (14%), Kinder Morgan Texas Pipeline, L.P. (10%), High Sierra Crude Oil and Marketing, LLC dba Interstate Petroleum Corporation (6%) and Enogex, Inc. (5%) collectively accounted for approximately 71% of our revenue. As of December 31, 2007, all of these companies, or their parent companies, were rated investment grade by Moody's Investors Service and Standard & Poor's Ratings Services, or we had letters of credit from investment grade financial institutions supporting our credit exposure.

Item 8. *Financial Statements and Supplementary Data*

The Report of Independent Registered Public Accounting Firm, Consolidated Financial Statements and supplementary financial data required for this Item are set forth on pages F-1 through F-54 of this Annual Report and are incorporated herein by reference.

Item 9. *Changes in and Disagreements with Accountants on Accounting and Financial Disclosure*

None.

Item 9A. *Controls and Procedures*

Management's Evaluation of Disclosure Controls and Procedures

We carried out an evaluation under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this Annual Report. Disclosure controls and procedures are defined as controls and other procedures that are designed to ensure that information required to be disclosed in the reports we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. Based on this evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective to ensure that information required to be disclosed in our reports filed or submitted under the Exchange Act is accumulated and communicated to management, including the Chief Executive Officer and Chief Financial Officer, to allow timely decisions regarding required disclosure.

Management's Annual Report on Internal Control over Financial Reporting

Our management, including the Chief Executive Officer and the Chief Financial Officer, is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Rules 13a-15(f) of the Exchange Act. Our management, with the participation of our Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f)) as of the end of the period covered by this report. We based our evaluation on the framework established by the Committee of Sponsoring Organizations of the Treadway Commission in the publication entitled, "Internal Control — Integrated Framework" (the "COSO Framework").

Based on our evaluation and the COSO Framework, we believe that, as of December 31, 2007, our internal control over financial reporting is effective to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. Deloitte & Touche LLP, our independent registered public accounting firm, has issued a report on our internal control over financial reporting, which is included in "Report of Independent Registered Public Accounting Firm" below.

Changes in Internal Controls Over Financial Reporting

Under the direction of our Chief Executive Officer and Chief Financial Officer, we evaluated our disclosure controls and procedures and internal control over financial reporting and concluded that (i) our disclosure controls and procedures were effective as of December 31, 2007, and (ii) no change in our internal control over financial reporting occurred during the quarter ended December 31, 2007, that has materially affected, or is reasonably likely to materially affect such internal control over financial reporting.

MANAGEMENT'S ANNUAL REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING AS OF DECEMBER 31, 2007

The management of Copano Energy, L.L.C. and its consolidated subsidiaries, including the Chief Executive Officer and the Chief Financial Officer, is responsible for establishing and maintaining adequate internal control over financial reporting, as defined in Rules 13a-15(f) and 15d-15(f) of the Exchange Act. The Company's management, with the participation of the Company's Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f)) as of the end of the period covered by this report. The Company based its evaluation on the framework established by the Committee of Sponsoring Organizations of the Treadway Commission in the publication entitled, "Internal Control — Integrated Framework" (the "COSO Framework"). Our assessment of internal controls over financial reporting included design effectiveness and operating effectiveness of internal control over financial reporting, as well as the safeguarding of our assets.

Our internal control system was designed to provide reasonable assurance to our management and Board of Directors regarding the preparation and fair presentation of published financial statements in accordance with generally accepted accounting principles. All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. A system of internal control may become inadequate over time because of changes in conditions or deterioration in the degree of compliance with the policies or procedures. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

In conducting our evaluation of the effectiveness of our internal control over financial reporting, we excluded the acquisitions of Cimmarron in May 2007 and Cantera in October 2007 due to their size and complexity. The Cimmarron acquisition constituted approximately 9% of total assets, 6% of total revenues, and 1% of total segment gross margin for the year ended December 31, 2007. The Cantera acquisition constituted 40% of total assets, and 1% each of total revenues and total segment gross margin for the year ended December 31, 2007. Such exclusion was in accordance with Securities and Exchange Commission guidance that an assessment of recently acquired business may be omitted in management's report on internal controls over financial reporting, providing the acquisition took place within twelve months of management's evaluation.

We are in the process of evaluating the internal control structure over the operations of Cimmarron and Cantera. We expect this effort will continue into future fiscal quarters of 2008 due to the magnitude of the business.

Based on our assessment, we believe that, as of December 31, 2007, our internal control over financial reporting is effective to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles based on the criteria of the COSO Framework.

Pursuant to the requirements of Rules 13a-15(f) and 15d-15(f) of the Securities Exchange Act of 1934, as amended, this Annual Report on Internal Control Over Financial Reporting has been signed below by the following persons on behalf of the registrant and in the capacities indicated below on February 29, 2008.

/s/ JOHN R. ECKEL, JR.	/s/ MATTHEW J. ASSIFF
John R. Eckel, Jr. Chairman of the Board of Directors and Chief Executive Officer	Matthew J. Assiff Senior Vice President and Chief Financial Officer

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Unitholders of Copano Energy, L.L.C and Subsidiaries:
Houston, Texas

We have audited the internal control over financial reporting of Copano Energy, L.L.C. and subsidiaries (the "Company") as of December 31, 2007, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. As described in Management's Annual Report on Internal Control Over Financial Reporting, management excluded from its assessment the internal control over financial reporting at Cimmarron Gathering, LP ("Cimmarron") and Cantera Natural Gas, LLC ("Cantera"), which were acquired on May 1, 2007 and October 1, 2007, respectively, and whose financial statements constitute 14% and 78% of net assets, 9% and 40% of total assets, 10% and 9% of revenues, and 3% and 1% of net income of the consolidated financial statement amounts, respectively, as of and for the year ended December 31, 2007. Accordingly, our audit did not include the internal control over financial reporting at Cimmarron and Cantera. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Annual Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, based on the criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2007 of the Company and our report dated February 29, 2008 expressed an unqualified opinion on those financial statements and included an explanatory paragraph on the required adoption of new accounting principles related to the accounting for conditional asset retirement obligations, share-based payments and purchases and sales of inventory with the same counterparty.

/s/ Deloitte & Touche LLP
Houston, Texas
February 29, 2008

Item 9B. ***Other Information***

None.

PART III

Item 10. *Directors and Executive Officers of the Registrant*

The information required by Item 10 is incorporated herein by reference to the applicable information in our Proxy Statement for our 2008 Annual Meeting of Unitholders set forth under the caption "Proposal One — Election of Directors," "The Board of Directors and its Committees" and "Executive Officers" to be filed with the SEC not later than 120 days after the close of the fiscal year.

Item 11. *Executive Compensation*

The information required by Item 11, including information concerning grants under our equity compensation plan for directors and employees, is incorporated herein by reference to the applicable information in our Proxy Statement for our 2008 Annual Meeting of Unitholders set forth under the captions "The Board of Directors and its Committees — Director Compensation," "The Board of Directors and its Committees — Compensation Committee Interlocks and Insider Participation," "Compensation Disclosure and Analysis," "Executive Compensation," "Report of the Compensation Committee" and "Section 16(a) Beneficial Ownership Reporting Compliance" to be filed with the SEC not later than 120 days after the close of the fiscal year.

Item 12. *Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters*

The information required by Item 12, including information concerning securities authorized for issuance under our equity compensation plan for directors and employees, is incorporated herein by reference to our Proxy Statement for our 2008 Annual Meeting of Unitholders set forth under the captions "Security Ownership of Certain Beneficial Owners and Management" and "Executive Compensation" to be filed with the SEC not later than 120 days after the close of the fiscal year.

Item 13. *Certain Relationships and Related Parties*

The information required by Item 13 is incorporated herein by reference to the applicable information in our Proxy Statement for our 2008 Annual Meeting of Unitholders set forth under the caption "Certain Relationships and Related Transactions" to be filed with the SEC not later than 120 days after the close of the fiscal year.

Item 14. *Principal Accountant Fees and Services*

The information required by Item 14 is incorporated herein by reference to the applicable information in our Proxy Statement for our 2008 Annual Meeting of Unitholders set forth under the caption "Proposal Two — Ratification of Independent Public Accountants" to be filed with the SEC not later than 120 days after the close of the fiscal year.

PART IV

Item 15. *Exhibits and Financial Statement Schedules*

(a)(1) and (2) Financial Statements

The consolidated financial statements of Copano Energy, L.L.C. and the financial statements of Bighorn Gas Gathering, L.L.C. are listed on the Index to Financial Statements to this Annual Report beginning on page F-1.

(a)(3) Exhibits

The following documents are filed as a part of this Annual Report or incorporated by reference.

Number	Description
2.1	Purchase Agreement dated as of August 31, 2007 among Copano Energy, L.L.C., Copano Energy/Rocky Mountains, L.L.C., and Cantera Resources Holdings LLC (incorporated by reference to Exhibit 2.1 to Current Report on Form 8-K filed October 25, 2007).
2.2	Contribution Agreement dated as of April 5, 2007 by and among Cimmarron Gathering GP, LLC, Taos Gathering, LP and Cimmarron Transportation, L.L.C. and Copano Energy, L.L.C. (incorporated by reference to Exhibit 2.1 to Current Report on Form 8-K filed April 11, 2007).
3.1	Certificate of Formation of Copano Energy Holdings, L.L.C. (now Copano Energy, L.L.C.) (incorporated by reference to Exhibit 3.1 to Registration Statement on Form S-1 filed July 30, 2004).
3.2	Certificate of Amendment to Certificate of Formation of Copano Energy Holdings, L.L.C. (now Copano Energy, L.L.C.) (incorporated by reference to Exhibit 3.2 to Registration Statement on Form S-1 filed July 30, 2004).
3.3	Third Amended and Restated Limited Liability Company Agreement of Copano Energy, L.L.C. (incorporated by reference to Exhibit 3.1 to Current Report on Form 8-K filed April 30, 2007).
3.4	Amendment No. 1 to Third Amended and Restated Limited Liability Company Agreement of Copano Energy, L.L.C. (incorporated by reference to Exhibit 3.1 to Current Report on Form 8-K filed May 4, 2007).
3.5	Amendment No. 2 to Third Amended and Restated Limited Liability Company Agreement of Copano Energy, L.L.C. dated October 19, 2007 (incorporated by reference to Exhibit 3.1 to Current Report on Form 8-K filed October 25, 2007).
3.6	Amendment No. 3 to Third Amended and Restated Limited Liability Company Agreement of Copano Energy, L.L.C., dated October 19, 2007 (incorporated by reference to Exhibit 3.2 to Current Report on Form 8-K filed October 25, 2007).
4.1	Indenture dated as of February 7, 2006, among Copano Energy, L.L.C., Copano Energy Finance Corporation, the Guarantors parties thereto and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to Current Report on Form 8-K filed February 8, 2006).
4.2	Rule 144A Global Note representing $224,500,000 principal amount of 8.125% Senior Notes due 2016 (incorporated by reference to Exhibit 4.2 to Current Report on Form 8-K filed February 8, 2006).
4.3	Regulation S Global Note representing $500,000 principal amount of 8.125% Senior Notes due 2016 (incorporated by reference to Exhibit 4.3 to Current Report on Form 8-K filed February 8, 2006).
4.4	Registration Rights Agreement dated as of May 1, 2007, by and among Copano Energy, L.L.C. and Cimmarron Gathering GP, LLC, Taos Gathering, LP and Cimmarron Transportation, LLC (incorporated by reference to Exhibit 4.1 to Current Report on Form 8-K filed May 4, 2007).
4.5	Registration Rights Agreement by and between Copano Energy, L.L.C. and Cantera Resources Holdings LLC, dated October 19, 2007 (incorporated by reference to Exhibit 4.1 to Current Report on Form 8-K filed October 25, 2007).
4.6	Registration Rights Agreement by and among Copano Energy, L.L.C. and the Purchasers, dated October 19, 2007 (incorporated by reference to Exhibit 4.2 to Current Report on Form 8-K filed October 25, 2007).
10.1	Form of Copano Energy, L.L.C. Long-Term Incentive Plan (incorporated by reference to Exhibit 10.5 to Amendment No. 3 to Registration Statement on Form S-1/A filed October 26, 2004).
10.2	First Amendment to Copano Energy, L.L.C. Long-Term Incentive Plan, dated October 27, 2005 (incorporated by reference to Exhibit 10.2 to Current Report on Form 8-K filed November 2, 2005).

Number	Description
10.3	Second Amendment to Copano Energy, L.L.C. Long-Term Incentive Plan, dated May 25, 2006 (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K filed May 30, 2006).
10.4	Administrative and Operating Services Agreement dated November 15, 2004, among Copano/Operations, Inc. and Copano Energy, L.L.C., and the Copano Operating Subsidiaries listed therein (incorporated by reference to Exhibit 3.4 to Post-Effective Amendment No. 1 to Registration Statement on Form S-1/A filed December 15, 2004).
10.5	First Amendment to Administrative and Operating Services Agreement (incorporated by reference to Exhibit 10.1 to Quarterly Report on Form 10-Q filed November 9, 2007).
10.6	Employment Agreement between Copano/Operations, Inc., R. Bruce Northcutt and the Copano Controlling Entities, dated April 9, 2003 (incorporated by reference to Exhibit 10.8 to Amendment No. 2 to Registration Statement on Form S-1/A filed October 12, 2004).
10.7	First Amendment to Employment Agreement between Copano/Operations, Inc., R. Bruce Northcutt and the Copano Controlling Entities, dated July 30, 2004 (incorporated by reference to Exhibit 10.9 to Amendment No. 2 to Registration Statement on Form S-1/A filed October 12, 2004).
10.8	Assignment and Assumption Agreement between Copano/Operations, Inc. and CPNO Services, L.P. effective January 1, 2005 with respect to Employment Agreement between Copano/Operations, Inc., R. Bruce Northcutt and the Copano Controlling Entities, as amended (incorporated by reference to Exhibit 10.10 to Annual Report on Form 10-K filed March 31, 2005).
10.9	Second Amendment to Employment Agreement between CPNO Services, L.P., R. Bruce Northcutt and the Copano Controlling Entities, effective March 1, 2005 (incorporated by reference to Exhibit 10.10 to Annual Report on Form 10-K filed March 31, 2005).
10.10	Employment Agreement between Copano/Operations, Inc. and James J. Gibson, III, dated as of October 1, 2004 (incorporated by reference to Exhibit 10.10 to Amendment No. 4 to Registration Statement on Form S-1/A filed November 2, 2004).
10.11	Assignment and Assumption Agreement between Copano/Operations, Inc. and CPNO Services, L.P. effective January 1, 2005 with respect to Employment Agreement between Copano/Operations, Inc. and James J. Gibson, III (incorporated by reference to Exhibit 10.10 to Annual Report on Form 10-K filed March 31, 2005).
10.12	First Amendment to Employment Agreement between CPNO Services, L.P. and James J. Gibson, III, effective March 1, 2005 (incorporated by reference to Exhibit 10.10 to Annual Report on Form 10-K filed March 31, 2005).
10.13	Employment Agreement between CPNO Services, L.P. and John A. Raber dated as of August 1, 2005 (incorporated by reference to Exhibit 10.32 to Quarterly Report on Form 10-Q filed August 15, 2005).
10.14	Employment Agreement between ScissorTail Energy, L.L.C. and Bruce Roderick dated as of August 1, 2005 (incorporated by reference to Exhibit 10.33 to Quarterly Report on Form 10-Q filed August 15, 2005).
10.15	Employment Agreement between ScissorTail Energy, L.L.C. and Sharon Robinson dated as of August 1, 2005 (incorporated by reference to Exhibit 10.34 to Quarterly Report on Form 10-Q filed August 15, 2005).
10.16	Employment Agreement between ScissorTail Energy, L.L.C. and Thomas Coleman dated as of August 1, 2005 (incorporated by reference to Exhibit 10.35 to Quarterly Report on Form 10-Q filed August 15, 2005).
10.17	Employment Agreement between ScissorTail Energy, L.L.C. and Lee E. Fiegener dated as of August 1, 2005 (incorporated by reference to Exhibit 10.36 to Quarterly Report on Form 10-Q filed August 15, 2005).
10.18	2004 Form of Restricted Unit Grant (Directors) (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K filed December 15, 2004).
10.19	2004 Form of Unit Option Grant (incorporated by reference to Exhibit 10.17 to Quarterly Report on Form 10-Q filed December 21, 2004).
10.20	2005 Form of Restricted Unit Grant (Employees) (incorporated by reference to Exhibit 4.4 to Registration Statement on Form S-8 filed February 11, 2005).
10.21	2005 Form of Unit Option Grant (incorporated by reference to Exhibit 4.5 to Registration Statement on Form S-8 filed February 11, 2005).
10.22	Form of Unit Option Grant (ScissorTail Energy, LLC Officers) (incorporated by reference to Exhibit 10.37 to Quarterly Report on Form 10-Q filed August 15, 2005).

Number	Description
10.23	Form of Restricted Unit Grant (ScissorTail Energy, LLC Officers) (incorporated by reference to Exhibit 10.38 to Quarterly Report on Form 10-Q filed August 15, 2005).
10.24	2006 Form of Restricted Unit Grant (Directors) (incorporated by reference to Exhibit 10.3 to Current Report on Form 8-K filed May 30, 2006).
10.25	2006 Form of Unit Option Grant (Employees) (incorporated by reference to Exhibit 10.2 to Current Report on Form 8-K filed May 30, 2006).
10.26	2006 Form of Restricted Unit Grant (Employees) (incorporated by reference to Exhibit 10.4 to Current Report on Form 8-K filed May 30, 2006).
10.27	November 2006 Form of Grant of Restricted Units (Directors) (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K filed November 20, 2006).
10.28	2007 Form of Phantom Unit Grant (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K filed June 18, 2007).
10.29	Copano Energy, L.L.C. Management Incentive Compensation Plan (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K filed March 2, 2005).
10.30	2007 Administrative Guidelines for the Copano Energy, L.L.C. Management Incentive Compensation Plan (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K filed February 20, 2007).
10.31	2008 Administrative Guidelines for the Copano Energy, L.L.C. Management Incentive Compensation Plan (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K filed February 27, 2008).
10.32	Form of Indemnification Agreement (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K filed November 2, 2005).
10.33	Copano Energy, L.L.C. Change in Control Severance Plan (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K filed December 18, 2007).
10.34	Lease Agreement dated as of October 17, 2000, between Plow Realty Company of Texas and Texas Gas Plants, L.P. (incorporated by reference to Exhibit 10.13 to Amendment No. 2 to Registration Statement on Form S-1/A filed October 12, 2004).
10.35	Lease Agreement dated as of December 3, 1964, between The Plow Realty Company of Texas and Shell Oil Company (incorporated by reference to Exhibit 10.14 to Amendment No. 2 to Registration Statement on Form S-1/A filed October 12, 2004).
10.36	Lease Agreement dated as of January 1, 1944, between The Plow Realty Company of Texas and Shell Oil Company, Incorporated (incorporated by reference to Exhibit 10.15 to Amendment No. 2 to Registration Statement on Form S-1/A filed October 12, 2004).
10.37†	Amended and Restated Gas Processing Contract entered into as of February 1, 2006, between Kinder Morgan Texas Pipeline, L.P. and Copano Processing, L.P. (incorporated by reference to Exhibit 10.1 to Quarterly Report on Form 10-Q filed May 10, 2006).
10.38	Loan Agreement dated as of September 29, 2006, among Copano Energy, L.L.C., as the Borrower, Banc of America Bridge LLC, as Administrative Agent, and The Other Lenders Party Hereto and Banc of America Securities LLC, as Sole Lead Arranger and Sole Lead Manager (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K filed October 5, 2006).
10.39	Amended and Restated Credit Agreement dated as of January 12, 2007, among Copano Energy, L.L.C., as the Borrower, Bank of America, N.A., as Administrative Agent and L/C Issuer, JPMorgan Chase Bank, N.A. and Wachovia Bank, National Association, as Co-Syndication Agents and The Other Lenders Party thereto and Banc of America Securities LLC, as Sole Lead Arranger and Sole Book Manager (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K filed January 19, 2007).
10.40*	First Amendment to Amended and Restated Credit Agreement, dated October 19, 2007.
12.1*	Statement of Computation of Ratios of Earnings to Fixed Changes.
21.1*	List of Subsidiaries.
23.1*	Consent of Deloitte & Touche LLP.
23.2*	Consent of Deloitte & Touche LLP.
31.1*	Sarbanes-Oxley Section 302 certification of John R. Eckel, Jr. (Chief Executive Officer) for Copano Energy, L.L.C.
31.2*	Sarbanes-Oxley Section 302 certification of Matthew J. Assiff (Chief Financial Officer) for Copano Energy, L.L.C.

Number	Description
32.1*	Sarbanes-Oxley Section 906 certification of John R. Eckel, Jr. (Chief Executive Officer) for Copano Energy, L.L.C.
32.2*	Sarbanes-Oxley Section 906 certification of Matthew J. Assiff (Chief Financial Officer) for Copano Energy, L.L.C.

* Filed herewith.

† Portions of this exhibit have been omitted pursuant to a request for confidential treatment.

(b) Exhibits

See Item 15(a)(3) above.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this Annual Report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Houston, State of Texas, on the 29th day of February 2008.

COPANO ENERGY, L.L.C.

By: /s/ JOHN R. ECKEL, JR.
John R. Eckel, Jr.
Chairman of the Board of Directors and
Chief Executive Officer

By: /s/ MATTHEW J. ASSIFF
Matthew J. Assiff
Senior Vice President and Chief Financial Officer

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

Signature	Title	Date
/s/ JOHN R. ECKEL, JR. John R. Eckel, Jr.	Chairman of the Board of Directors and Chief Executive Officer (Principal Executive Officer)	February 29, 2008
/s/ MATTHEW J. ASSIFF Matthew J. Assiff	Senior Vice President and Chief Financial Officer (Principal Financial Officer)	February 29, 2008
/s/ LARI PARADEE Lari Paradee	Vice President and Controller (Principal Accounting Officer)	February 29, 2008
/s/ JAMES G. CRUMP James G. Crump	Director	February 29, 2008
/s/ ERNIE L. DANNER Ernie L. Danner	Director	February 29, 2008
/s/ MICHAEL L. JOHNSON Michael L. Johnson	Director	February 29, 2008
/s/ SCOTT A. GRIFFITHS Scott A. Griffiths	Director	February 29, 2008
/s/ T. WILLIAM PORTER T. William Porter	Director	February 29, 2008
/s/ WILLIAM L. THACKER William L. Thacker	Director	February 29, 2008

COPANO ENERGY, L.L.C.

INDEX TO FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Unitholders of Copano Energy, L.L.C and Subsidiaries:
Houston, Texas

We have audited the accompanying consolidated balance sheets of Copano Energy, L.L.C. and subsidiaries (the "Company") as of December 31, 2007 and 2006, and the related consolidated statements of operations, members' capital and comprehensive income (loss), and cash flows for each of the three years in the period ended December 31, 2007. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Copano Energy, L.L.C. and subsidiaries at December 31, 2007 and 2006, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2007, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 5 to the financial statements, effective December 31, 2005, the Company changed its accounting for conditional asset retirement obligations. As discussed in Notes 2 and 8 to the financial statements, effective January 1, 2006, the Company changed its accounting for share-based payments. As discussed in Note 2 effective April 1, 2006, the Company changed its accounting for purchases and sales of inventory with the same counterparty.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2007, based on the criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 29, 2008 expressed an unqualified opinion on the Company's internal control over financial reporting and excludes internal control over financial reporting relating to the operations acquired of Cantera Natural Gas, LLC and Cimmarron Gathering, LP.

/s/ Deloitte & Touche LLP

Houston, Texas
February 29, 2008

COPANO ENERGY, L.L.C. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31, 2007	December 31, 2006
	(In thousands, except unit information)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 72,665	$ 39,484
Accounts receivable, net	127,534	67,095
Risk management assets	3,289	13,973
Prepayments and other current assets	3,881	3,166
Total current assets	207,369	123,718
Property, plant and equipment, net	694,727	566,927
Intangible assets, net	200,546	93,372
Investment in unconsolidated affiliates	632,725	19,378
Risk management assets	10,598	23,826
Other assets, net	23,118	11,837
Total assets	$1,769,083	$839,058
LIABILITIES AND MEMBERS' CAPITAL		
Current liabilities:		
Accounts payable	$ 147,046	$ 91,668
Notes payable	—	1,495
Accrued interest	11,319	6,261
Accrued tax liability	3,919	—
Risk management liabilities	27,710	944
Other current liabilities	12,931	5,354
Total current liabilities	202,925	105,722
Long-term debt (includes $773 bond premium as of December 31, 2007)	630,773	255,000
Deferred tax provision	1,231	—
Risk management and other noncurrent liabilities	40,018	5,750
Commitments and contingencies (Note 13)		
Members' capital:		
Common units, no par value, 47,366,048 units and 35,190,590 units issued and outstanding as of December 31, 2007 and 2006, respectively	661,585	480,797
Class C units, no par value, 1,184,557 units and 0 units issued and outstanding as of December 31, 2007 and 2006, respectively	40,492	—
Class D units, no par value, 3,245,817 units and 0 units issued and outstanding as of December 31, 2007 and 2006, respectively	112,454	—
Class E units, no par value, 5,598,839 units and 0 units issued and outstanding as of December 31, 2007 and 2006, respectively	175,634	—
Subordinated units, no par value, 7,038,252 units issued and outstanding as of December 31, 2006	—	10,379
Paid-in capital	23,773	10,585
Accumulated (deficit) earnings	(7,867)	2,918
Other comprehensive loss	(111,935)	(32,093)
	894,136	472,586
Total liabilities and members' capital	$1,769,083	$839,058

The accompanying notes are an integral part of these consolidated financial statements.

COPANO ENERGY, L.L.C. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2007	2006	2005
	(In thousands, except per unit information)		
Revenue:			
Natural gas sales	$ 518,431	$448,054	$496,906
Natural gas liquids sales	491,432	369,892	224,695
Crude oil sales	77,142	—	—
Transportation, compression and processing fees	22,306	16,232	15,110
Condensate and other	32,349	26,094	11,032
Total revenue	1,141,660	860,272	747,743
Costs and expenses:			
Cost of natural gas and natural gas liquids	853,964	669,158	641,315
Cost of crude oil purchases	73,814	—	—
Transportation	6,948	3,026	2,337
Operations and maintenance	41,156	32,484	18,459
Depreciation and amortization	39,967	31,993	17,052
General and administrative	34,638	26,535	18,156
Taxes other than income	2,637	2,061	1,178
Equity in earnings from unconsolidated affiliates	(2,850)	(1,297)	(927)
Total costs and expenses	1,050,274	763,960	697,570
Operating income	91,386	96,312	50,173
Other income (expense):			
Interest and other income	2,854	1,706	640
Interest and other financing costs	(29,351)	(32,904)	(20,461)
Income before income taxes	64,889	65,114	30,352
Provision for income taxes	(1,714)	—	—
Net income	$ 63,175	$ 65,114	$ 30,352
Basic net income per common unit:			
Net income per common unit	$ 1.48	$ 1.77	$ 1.20
Weighted average number of common units	42,456	29,752	16,984
Diluted net income per common unit:			
Net income per common unit	$ 1.36	$ 1.75	$ 1.15
Weighted average number of common units	46,516	30,180	26,508
Basic net income per subordinated unit:			
Net income per subordinated unit	$ 0.21	$ 1.77	$ 1.20
Weighted average number of subordinated units	848	7,038	7,038
Diluted net income per subordinated unit:			
Net income per subordinated unit	$ 0.21	$ 1.76	$ 1.20
Weighted average number of subordinated units	848	7,038	7,038
Basic net income per Class B unit:			
Net income per Class B unit	$ —	$ —	$ 0.66
Weighted average number of Class B units	—	—	2,303
Diluted net income per Class B unit:			
Net income per Class B unit	$ —	$ —	$ 0.39
Weighted average number of Class B units	—	—	2,303

The accompanying notes are an integral part of these consolidated financial statements.

COPANO ENERGY, L.L.C. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2007	2006	2005
		(In thousands)	
Cash Flows From Operating Activities:			
Net income	$ 63,175	$ 65,114	$ 30,352
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	39,967	31,993	17,052
Amortization of debt issue costs	1,666	4,462	5,723
Equity in earnings from unconsolidated affiliates	(2,850)	(1,297)	(927)
Distributions from unconsolidated affiliates	3,706	—	—
Equity-based compensation	3,223	1,910	1,283
Deferred tax provision	1,231	—	—
Other noncash items	(136)	176	26
Changes in assets and liabilities, net of acquisitions:			
Accounts receivable	(34,890)	16,459	(16,725)
Prepayments and other current assets	(204)	1,372	2,771
Risk management assets	(21,720)	(23,014)	(42,635)
Accounts payable	38,232	(6,867)	19,720
Other current liabilities	36,818	1,371	(16,360)
Net cash provided by operating activities	128,218	91,679	280
Cash Flows From Investing Activities:			
Additions to property, plant and equipment	(80,898)	(49,033)	(9,602)
Additions to intangible assets	(3,406)	(1,237)	(95,586)
Acquisitions, net of cash acquired	(641,097)	(9,074)	(384,154)
Investment in unconsolidated affiliates	(1,727)	(10,438)	(2,722)
Distributions from unconsolidated affiliates	676	—	—
Escrow cash	—	—	1,001
Other	(600)	(509)	(645)
Net cash used in investing activities	(727,052)	(70,291)	(491,708)
Cash Flows From Financing Activities:			
Repayments of long-term debt	(288,000)	(506,500)	(94,000)
Proceeds from long-term debt	663,781	363,500	435,000
Repayment of short-term notes payable	(1,495)	(1,842)	(1,207)
Deferred financing costs	(10,677)	(7,035)	(9,802)
Distributions to unitholders	(73,629)	(46,977)	(23,366)
Proceeds from follow-on public offering of common units, net of underwriting discounts and commissions of $7,216	—	162,725	—
Proceeds from private placement of common units	157,125	25,000	64,499
Proceeds from private placement of Class B units	—	—	135,503
Proceeds from private placement of Class E units	177,875	—	—
Capital contributions from Pre-IPO Investors (Note 8)	9,965	4,607	4,068
Equity offering costs	(4,741)	(1,057)	(1,074)
Proceeds from option exercises	1,811	378	89
Net cash provided by (used in) financing activities	632,015	(7,201)	509,710
Net increase in cash and cash equivalents	33,181	14,187	18,282
Cash and cash equivalents, beginning of year	39,484	25,297	7,015
Cash and cash equivalents, end of year	$ 72,665	$ 39,484	$ 25,297

The accompanying notes are an integral part of these consolidated financial statements.

COPANO ENERGY, L.L.C. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF MEMBERS' CAPITAL AND COMPREHENSIVE INCOME (LOSS)

	Common		Class B		Class C		Class D		Class E		Subordinated							
	Number of Units	Common Units	Number of Units	Class B Units	Number of Units	Class C Units	Number of Units	Class D Units	Number of Units	Class E Units	Number of Units	Subordinated Units	Paid-in Capital	Accumulated Earnings (Deficit)	Deferred Compensation	Accumulated Other Comprehensive Loss	Total	Total Comprehensive Income
Balance, December 31, 2004	14,112	$ 94,325	—	$ —	—	$ —	—	$ —	—	$ —	7,038	$ 10,379	$ —	$(21,927)	$ (421)	$ —	82,356	
Capital contributions from Pre-IPO Investors	—	—	—	—	—	—	—	—	—	—	—	—	4,068	—	—	—	4,068	$ —
Private placement of units	4,164	64,499	9,662	135,503	—	—	—	—	—	—	—	—	—	—	—	—	200,002	—
Equity offering costs	—	(777)	—	(858)	—	—	—	—	—	—	—	—	—	—	—	—	(1,635)	—
Conversion of Class B units into common units	9,662	134,645	(9,662)	(134,645)	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Distributions to unitholders	—	—	—	—	—	—	—	—	—	—	—	—	—	(23,366)	—	—	(23,366)	—
Option exercises	10	89	—	—	—	—	—	—	—	—	—	—	—	—	—	—	89	—
Issuance of restricted units	254	4,811	—	—	—	—	—	—	—	—	—	—	—	—	(4,811)	—	—	—
Equity-based compensation	—	—	—	—	—	—	—	—	—	—	—	—	—	—	1,283	—	1,283	—
Net income	—	—	—	—	—	—	—	—	—	—	—	—	—	30,352	—	—	30,352	30,352
Unrealized loss-change in fair value of derivatives	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	(11,346)	(11,346)	(11,346)
Comprehensive income																		$ 19,006
Balance, December 31, 2005	28,202	297,592	—	—	—	—	—	—	—	—	7,038	10,379	4,068	(14,941)	(3,949)	(11,346)	281,803	
Capital contributions from Pre-IPO Investors	—	—	—	—	—	—	—	—	—	—	—	—	4,607	—	—	—	4,607	—
Private placement of units	1,418	25,000	—	—	—	—	—	—	—	—	—	—	—	—	—	—	25,000	—
Issuance of common units to public	5,750	169,941	—	—	—	—	—	—	—	—	—	—	—	—	—	—	169,941	—
Equity offering costs	—	(8,165)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	(8,165)	—
Distributions to unitholders	—	—	—	—	—	—	—	—	—	—	—	—	—	(47,255)	—	—	(47,255)	—
Option exercises	30	378	—	—	—	—	—	—	—	—	—	—	—	—	—	—	378	—
Adoption of SFAS No. 123(R) — reversal of deferred compensation related to restricted units	(277)	(3,949)	—	—	—	—	—	—	—	—	—	—	—	—	3,949	—	—	—
Equity-based compensation	—	—	—	—	—	—	—	—	—	—	—	—	1,910	—	—	—	1,910	—
Vested restricted units	68	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Net income	—	—	—	—	—	—	—	—	—	—	—	—	—	65,114	—	—	65,114	65,114
Derivative settlements reclassified to income	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	431	431	431
Unrealized loss-change in fair value of derivatives	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	(21,178)	(21,178)	(21,178)
Comprehensive income																		$ 44,367
Balance, December 31, 2006	35,191	480,797	—	—	—	—	—	—	—	—	7,038	10,379	10,585	2,918	—	(32,093)	472,586	
Capital contributions from Pre-IPO Investors	—	—	—	—	—	—	—	—	—	—	—	—	9,965	—	—	—	9,965	—
Conversion of subordinated units into common units	7,038	10,379	—	—	—	—	—	—	—	—	(7,038)	(10,379)	—	—	—	—	—	—
Private placement of units	4,533	157,125	—	—	1,579	54,000	3,246	112,500	5,599	177,875	—	—	—	—	—	—	501,500	—
Offering costs	—	(2,027)	—	—	—	(8)	—	(46)	—	(2,241)	—	—	—	—	—	—	(4,322)	—
Conversion of Class C units into common units	395	13,500	—	—	(395)	(13,500)	—	—	—	—	—	—	—	—	—	—	—	—
Distributions to unitholders	—	—	—	—	—	—	—	—	—	—	—	—	—	(73,960)	—	—	(73,960)	—
Option exercises	115	1,811	—	—	—	—	—	—	—	—	—	—	—	—	—	—	1,811	—
Equity-based compensation	—	—	—	—	—	—	—	—	—	—	—	—	3,223	—	—	—	3,223	—
Vested restricted units	94	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Net income	—	—	—	—	—	—	—	—	—	—	—	—	—	63,175	—	—	63,175	63,175
Derivative settlements reclassified to income	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	8,296	8,296	8,296
Unrealized loss-change in fair value of derivatives	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	(88,138)	(88,138)	(88,138)
Comprehensive loss																		$(16,667)
Balance, December 31, 2007	47,366	$661,585	—	$ —	1,184	$ 40,492	3,246	$112,454	5,599	$175,634	—	$ —	$23,773	$ (7,867)	$ —	$(111,935)	$894,136	

The accompanying notes are an integral part of these consolidated financial statements.

COPANO ENERGY, L.L.C. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1 — Organization

Copano Energy, L.L.C., a Delaware limited liability company, was formed in August 2001 to acquire entities owning businesses operating under the Copano name since 1992. We, through our wholly owned subsidiaries, provide midstream energy services, including natural gas gathering, compression, dehydration, treating, transportation, processing and conditioning services. Our assets are primarily located in Oklahoma, Texas and Wyoming. *Unless the context requires otherwise, references to "Copano," "we," "our," "us" or like terms refer to Copano Energy, L.L.C. and its wholly owned subsidiaries.*

Our natural gas pipelines collect natural gas from designated points near producing wells and transport these volumes to third-party pipelines, our gas processing plants, third-party processing plants, local distribution companies and power generation facilities. Natural gas delivered to our gas processing plants, either on our pipelines or third-party pipelines, is treated to remove contaminants, conditioned or processed to extract mixed natural gas liquids, or NGLs, and then fractionated or separated, to the extent commercially desirable, into select component NGL products, including ethane, propane, isobutane, normal butane, natural gasoline and stabilized condensate. In addition to our natural gas pipelines, we operate the NGL pipelines and a crude oil pipeline. As discussed in Note 4, in October 2007, we completed the acquisition of Cantera Natural Gas, LLC ("Cantera"), which expanded Copano's geographic footprint into the Powder River Basin of Wyoming. We refer to our operations (i) conducted through our subsidiaries operating in Oklahoma, including our crude oil pipeline, collectively as our "Oklahoma" segment, (ii) conducted through our subsidiaries operating in Texas and Louisiana collectively as our "Texas" segment and (iii) conducted through our subsidiaries operating in Wyoming collectively as our "Rocky Mountains" segment.

Note 2 — Summary of Significant Accounting Policies

Basis of Presentation and Principles of Consolidation

The accompanying consolidated financial statements and related notes include our assets, liabilities and results of operations for each of the periods presented. All significant intercompany accounts and transactions are eliminated in the consolidated financial statements.

On February 15, 2007, our Board of Directors approved a two-for-one split of our outstanding common units. The split entitled each unitholder of record at the close of business on March 15, 2007 to receive one additional common unit for every common unit held on that date. The additional common units were distributed to unitholders on March 30, 2007. Net income per unit, weighted average units outstanding and distributions per unit for all periods and any references to common units, restricted units and options to purchase common units have been adjusted to reflect this two-for-one split.

Investments in Unconsolidated Affiliates

We own a 62.5% equity investment in Webb/Duval Gatherers ("Webb Duval"), a Texas general partnership, a majority interest in Southern Dome, LLC ("Southern Dome"), a Delaware limited liability company, a 51% interest in Bighorn Gas Gathering, L.L.C. ("Bighorn"), a Delaware limited liability company, and a 37.04% interest in Fort Union Gas Gathering, L.L.C. ("Fort Union"), a Delaware limited liability company. Although we are the managing partner or member in each of these equity investments and, in some cases, own a majority interest in these equity investments, we account for these investments using the equity method of accounting because the minority general partners or members have substantive participating rights with respect to the management of each of these equity investments. Equity in earnings from our unconsolidated affiliates is included in income from operations as the operations of each of our unconsolidated affiliates are integral to our operations. (See Note 6.)

Note 2 — Summary of Significant Accounting Policies (Continued)

Use of Estimates

In preparing the financial statements in conformity with accounting policies generally accepted in the United States of America, management must 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 the financial statements. Although our management believes the estimates are appropriate, actual results can differ materially from those estimates.

Cash and Cash Equivalents

Cash and cash equivalents include certificates of deposit with maturities of three months or less at the time of purchase.

Concentration and Credit Risk

Financial instruments that potentially subject us to concentrations of credit risk consist principally of cash and cash equivalents and accounts receivable.

We place our cash and cash equivalents with high-quality financial institutions and in money market funds. We derive our revenue from customers primarily in the natural gas and utility industries. These industry concentrations have the potential to impact our overall exposure to credit risk, either positively or negatively, in that our customers could be affected by similar changes in economic, industry or other conditions. However, we believe that the credit risk posed by this industry concentration is offset by the creditworthiness of our customer base. Our portfolio of accounts receivable is comprised primarily of mid-size to large domestic corporate entities.

Allowance for Doubtful Accounts

We extend credit to customers and other parties in the normal course of business. Estimated losses on accounts receivable are provided through an allowance for doubtful accounts. In evaluating the level of established reserves, we make judgments regarding economic conditions, each party's ability to make required payments and other factors. As the financial condition of any party changes, other circumstances develop or additional information becomes available, adjustments to the allowance for doubtful accounts may be required. We have established various procedures to manage our credit exposure, including initial credit approvals, credit limits and rights of offset. We also manage our credit risk using prepayments and guarantees to ensure that our management's established credit criteria are met. The activity in the allowance for doubtful accounts is as follows (in thousands):

	Balance at Beginning of Period	Charged to Expense	Write-Offs, Net of Recoveries	Balance at End of Period
Year ended December 31, 2007	$ 64	$ 69	$ (2)	$131
Year ended December 31, 2006	64	42	(42)	64
Year ended December 31, 2005	356	(285)	(7)	64

Property, Plant and Equipment

Our property, plant and equipment consist of intrastate gas transmission systems, gas gathering systems, gas processing, conditioning and treating facilities and other related facilities, and are carried at cost less accumulated depreciation. We charge repairs and maintenance against income when incurred and capitalize renewals and

Note 2 — Summary of Significant Accounting Policies (Continued)

betterments, which extend the useful life or expand the capacity of the assets. We calculate depreciation on the straight-line method based on the estimated useful lives of our assets as follows:

	Useful Lives
Pipelines and equipment	15-30 years
Gas processing plants and equipment	20-30 years
Other property and equipment	3-7 years

We capitalize interest on major projects during extended construction time periods. Such interest is allocated to property, plant and equipment and amortized over the estimated useful lives of the related assets. We capitalized $932,000 and $693,000 of interest related to major projects during the years ended December 31, 2007 and 2006, respectively. No interest was capitalized during 2005.

Intangible Assets

Our intangible assets consist of rights-of-way, easements, contracts and an acquired customer relationship. We amortize intangible assets over the contract term or estimated useful life, as applicable, using the straight-line method. Amortization expense was $7,585,000, $5,417,000 and $2,503,000 for the years ended December 31, 2007, 2006 and 2005, respectively. Estimated aggregate amortization expense for each of the five succeeding fiscal years is approximately: *2008* — $10,322,000; *2009* — $10,253,000; *2010* — $10,225,000; *2011* — $10,213,000; and *2012* — $10,162,000. Intangible assets consisted of the following (in thousands):

	December 31, 2007	December 31, 2006
Rights-of-way and easements, at cost	$104,428	$60,931
Less accumulated amortization for rights-of-way and easements	(8,923)	(6,520)
Contracts	112,385	42,444
Less accumulated amortization for contracts	(7,833)	(4,009)
Customer relationship	725	725
Less accumulated amortization for customer relationship	(236)	(199)
Intangible assets, net	$200,546	$93,372

For the years ended December 31, 2007 and 2006, the weighted average amortization period for all of our intangible assets was 22 years and 19 years, respectively. The weighted average amortization period for our rights-of-way and easements and contracts was 24.5 years and 12.9 years, respectively, as of December 31, 2007. The weighted average amortization period for our rights-of-way and easements and contracts was 22.9 years and 13.6 years, respectively, as of December 31, 2006.

Asset Impairment

We review long-lived assets for impairment whenever there is evidence that the carrying value of such assets may not be recoverable. This review consists of comparing the carrying value of the asset with the asset's expected future undiscounted cash flows without interest costs. An impairment loss would be recognized when estimated future cash flows expected to result from the use of the asset and its eventual disposition are less than the asset's carrying value. Estimates of expected future cash flows represent our management's best estimate based on reasonable and supportable assumptions.

Note 2 — Summary of Significant Accounting Policies (Continued)

Other Assets

Other assets primarily consist of costs associated with debt issuance costs net of related accumulated amortization. Amortization of other assets is calculated using the straight-line method over the maturity of the associated debt or the term of the associated contract.

Transportation and Exchange Imbalances

In the course of transporting natural gas and NGLs for others, we may receive for redelivery different quantities of natural gas or NGLs than the quantities we ultimately redeliver. These differences are recorded as transportation and exchange imbalance receivables or payables that are recovered or repaid through the receipt or delivery of natural gas or NGLs in future periods, if not subject to cashout provisions. Imbalance receivables are included in accounts receivable, and imbalance payables are included in accounts payable on the consolidated balance sheets at current market prices in effect for the reporting period of the outstanding imbalances. As of December 31, 2007 and 2006, we had imbalance receivables totaling $526,000 and $586,000 and imbalance payables totaling $158,000 and $231,000, respectively. Changes in market value and the settlement of any such imbalance at a price greater than or less than the recorded imbalance results in an upward or downward adjustment, as appropriate, to the cost of natural gas sold.

Asset Retirement Obligations

In June 2001, the Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standards ("SFAS") No. 143, *"Accounting for Asset Retirement Obligations."* This statement requires us to record the fair value of a liability for legal obligations associated with the retirement obligations of tangible long-lived assets in the period in which the obligation is incurred and can be reasonably estimated. When the liability is initially recorded, a corresponding increase in the carrying amount of the related long-lived asset is recorded. Over time, accretion of the liability is recognized each period, and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement of the liability, an entity either settles the obligation for its recorded amount or incurs a gain or loss on settlement.

Under the implementation guidelines of SFAS No. 143, we reviewed our long-lived assets for asset retirement obligations ("ARO") and, based on our review, determined that we were not required to recognize any potential liabilities under SFAS 143. Amortization of the ARO asset and accretion of the ARO liability that may be required in the future will be recognized in earnings.

In March 2005, the FASB issued FASB Interpretation No. ("FIN") 47, *"Accounting for Conditional Asset Retirement Obligations, an interpretation of FASB Statement No. 143."* FIN 47 clarifies that the term conditional asset retirement obligation as used in SFAS No. 143, refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional upon a future event that may not be within the control of the entity. Even though uncertainty about the timing and/or method of settlement exists and may be conditional upon a future event, the obligation to perform the asset retirement activity is unconditional. Accordingly, an entity is required to recognize a liability for the fair value of a conditional asset retirement obligation if the fair value of the liability can be reasonably estimated. In these circumstances, we are required to determine if there is a range of potential settlement dates and the probabilities associated with this range based on a variety of factors, including our past practice, industry practice, management's intent, and the asset's economic life. The fair value of a liability for the conditional asset retirement obligation should be recognized when incurred generally upon acquisition, construction or development or through the normal operation of the asset. SFAS No. 143 acknowledges that in some cases, sufficient information may not be available to reasonably estimate the fair value of an asset retirement obligation. FIN 47 also clarifies when an entity would have sufficient information to reasonably estimate the fair value of an asset retirement obligation. We adopted FIN 47 effective December 31,

Note 2 — Summary of Significant Accounting Policies (Continued)

2005, and the adoption of FIN 47 did not have a material impact on our consolidated cash flows, results of operations or financial position. See Note 5.

Revenue Recognition

Our natural gas and NGL revenue is recognized in the period when the physical product is delivered to the customer and in an amount based on contract pricing.

Our sale and purchase arrangements are primarily accounted for on a gross basis in the statements of operations as natural gas sales and costs of natural gas, respectively. These transactions are contractual arrangements that establish the terms of the purchase of natural gas at a specified location and the sale of natural gas at a different location at the same or at another specified date. These arrangements are detailed either jointly, in a single contract or separately, in individual contracts that are entered into concurrently or in contemplation of one another with a single or multiple counterparties. Both transactions require physical delivery of the natural gas, and transfer of the risk and reward of ownership are evidenced by title transfer, assumption of environmental risk, transportation scheduling, credit risk and counterparty nonperformance risk.

On occasion, we enter into buy/sell arrangements that are accounted for on a net basis in the statements of operations as either a net natural gas sale or a net cost of natural gas, as appropriate. These purchase and sale transactions are generally with the same counterparty, for the same delivery period, for similar quantities and negotiated in contemplation of one another.

In September 2005, the Emerging Issues Task Force ("EITF") of the FASB reached consensus on the issue of accounting for buy/sell arrangements as part of its EITF Issue No. 04-13, *"Accounting for Purchases and Sales of Inventory with the Same Counterparty"* ("Issue 04-13"). As part of Issue 04-13, the EITF requires that all buy/sell arrangements be reflected on a net basis, such that the purchase and sale are netted and shown as either a net purchase or a net sale in the statement of operations. This requirement is effective for new arrangements entered into after March 31, 2006. Periods prior to March 31, 2006 have not been restated. Our adoption of Issue 04-13 did not have a material effect on our financial position, results of operations or cash flows. The following table illustrates the effect of Issue 04-13 on our natural gas sales revenue and cost of natural gas and NGLs for all periods presented in our consolidated statements of operations:

	Year Ended December 31, 2006	Year Ended December 31, 2005
Natural gas sales revenue:		
As reported	$448,054	$496,906
"As if" presented net under Issue 04-13	$448,054	$464,798
Cost of natural gas and natural gas liquids:		
As reported	$669,158	$641,315
"As if" presented net under Issue 04-13	$669,158	$609,207

Transportation, compression and processing-related revenue are recognized in the period when the service is provided and include our fee-based service revenue for services such as transportation, compression and processing, including processing under tolling arrangements.

Derivatives

SFAS No. 133, *"Accounting for Derivative Instruments and Hedging Activities,"* as amended, establishes accounting and reporting standards for derivative instruments, including certain derivative instruments embedded in other contracts, and for hedging activities. In accordance with SFAS No. 133, we recognize all derivatives as either risk management assets or liabilities in our consolidated balance sheets and measure those instruments at fair

Note 2 — Summary of Significant Accounting Policies (Continued)

value. Changes in the fair value of financial instruments over time are recognized into earnings unless specific hedging criteria are met. If the financial instruments meet the hedging criteria, changes in fair value will be recognized in earnings for fair value hedges and in other comprehensive income for the effective portion of cash flow hedges. Ineffectiveness in cash flow hedges is recognized in earnings in the period in which the ineffectiveness occurs. Gains and losses on cash flow hedges are reclassified to operating revenue as the forecasted transactions occur. We included changes in our risk management activities in cash flow from operating activities on the consolidated statement of cash flows.

SFAS No. 133 does not apply to contracts for normal purchases and normal sales. Contracts for normal purchases and normal sales provide for the purchase or sale of something other than a financial instrument or derivative instrument and for delivery in quantities expected to be used or sold by the reporting entity over a reasonable period in the normal course of business. Our forward natural gas purchase and sales contracts, most of which have terms ranging between one and five years, are designated normal purchases and sales. However, we do have a small number of contracts whose terms extend through the life of the dedicated production.

We use financial instruments such as puts, calls, swaps and other derivatives to mitigate the risks to earnings and cash flows resulting from changes in commodity prices and interest rates. We recognize these transactions as assets and liabilities on our consolidated balance sheet based on the instrument's fair value. The majority of our financial instruments have been designated and accounted for as cash flow hedges except as discussed in Note 11.

Income Taxes

Three of our wholly owned subsidiaries, Copano General Partners, Inc. ("CGP") and Copano Energy Finance Corporation ("CEFC"), both Delaware corporations, and CPNO Services, L.P. ("CPNO Services"), a Texas Partnership, are the only entities within our consolidated group subject to federal income taxes. CGP's operations primarily include its indirect ownership of the managing general partner interest in certain of our Texas operating entities. CEFC was formed in July 2005 and is a co-issuer of the senior notes issued in February 2006 and November 2007 (see Note 7). We reimburse CPNO Services for administrative and operating costs, including payroll and benefits expense, for certain of our field and administrative personnel. As of December 31, 2007, CGP and CPNO Services have estimated a combined net operating loss ("NOL") carryforward of approximately $1,717,000, for which a valuation allowance had been recorded. We recognized no significant income tax expense for the years ended December 31, 2007, 2006 and 2005. Except for income allocated with respect to CGP, CEFC and CPNO Services, our income is taxable directly to our unitholders.

We do not provide for federal income taxes in the accompanying consolidated financial statements, as we are not subject to entity-level federal income tax. However, we are subject to the Texas margin tax, which is imposed at a maximum effective rate of 0.7% on our annual "margin," as defined in the recently enacted Texas margin tax statute. The first annual taxable period began January 1, 2007, and the first returns are due in 2008. Our annual margin generally will be calculated as our revenues for federal income tax purposes less the "cost of the products sold" as defined in the statute. Under the provisions of SFAS No. 109, *"Accounting for Income Taxes,"* we are required to record the effects on deferred taxes for a change in tax rates or tax law in the period that includes the enactment date. Under SFAS No. 109, taxes based on income, like the Texas margin tax, are accounted for using the liability method under which deferred income taxes are recognized for the future tax effects of temporary differences between the financial statement carrying amounts and the tax basis of existing assets and liabilities using the enacted statutory tax rates in effect at the end of the period. A valuation allowance for deferred tax assets is recorded when it is more likely than not that the benefit from the deferred tax asset will not be realized. The provision for the Texas margin tax totaled $1,714,000 for the year ended December 31, 2007, comprised of $483,000 related to the current provision and a $1,231,000 deferred tax provision related to the cumulative effect of temporary book/tax timing differences associated with depreciation.

Note 2 — Summary of Significant Accounting Policies (Continued)

In June 2006, the FASB issued FIN 48, *"Accounting for Uncertainty in Income Taxes — an Interpretation of FASB Statement No. 109."* FIN 48 clarifies the accounting for uncertainty in income taxes recognized in an entity's financial statements in accordance with SFAS No. 109 by prescribing thresholds and attributes for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. The provisions of FIN 48 became effective as of the beginning of our 2007 fiscal year and our adoption of FIN 48 did not have a material impact on our consolidated financial position.

In connection with the Cantera Acquisition discussed in Note 4, we assumed an income tax liability for contingencies and accrued interest related to the reorganization of Cantera in 2004. The previous owners of Cantera are obligated to indemnify us in full for any obligation arising out of the potential income tax liability; thus our accompanying consolidated balance sheets include $3,436,000 in accounts receivable relating to the indemnity and in other current liabilities relating to the income tax contingencies, including $69,000 of accrued interest for the period from October 1, 2007 through December 31, 2007.

Net Income Per Unit

Net income per unit is calculated in accordance with SFAS No. 128, "*Earnings Per Share,*" and EITF Issue No. 03-6 ("Issue 03-6"), *"Participating Securities and the Two-Class Method under Financial Accounting Standards Board Statement No. 128."* SFAS No. 128 and Issue 03-6 specify the use of the two-class method of computing earnings per unit when participating or multiple classes of securities exist. Under this method, undistributed earnings for a period are allocated based on the contractual rights of each security to share in those earnings as if all of the earnings for the period had been distributed.

Basic net income per unit excludes dilution and is computed by dividing net income attributable to each respective class of units by the weighted average number of units outstanding for each respective class during the period. Dilutive net income per unit reflects potential dilution that could occur if securities or other contracts to issue common units were exercised or converted into common units except when the assumed exercise or conversion would have an anti-dilutive effect on net income per unit. Dilutive net income per unit is computed by dividing net income attributable to each respective class of units by the weighted average number of units outstanding for each respective class of units during the period increased by the number of additional units that would have been outstanding if the dilutive potential units had been exercised.

Note 2 — Summary of Significant Accounting Policies (Continued)

Basic and diluted net income per common unit is calculated as follows:

	Year Ended December 31,		
	2007	2006	2005
	(In thousands, except per unit information)		
Net income	$63,175	$ 65,114	$30,352
Less net income attributable to subordinated units	(175)	(12,457)	(8,446)
Less net income attributable to Class B units	—	—	(1,526)
Net income available — basic common units	63,000	52,657	20,380
Net income reallocated from subordinated units	175	39	8,446
Net income reallocated from to Class B units	—	—	1,526
Net income available — diluted common units	$63,175	$ 52,696	$30,352
Basic weighted average common units	42,456	29,752	16,984
Dilutive weighted average common units**	46,516	30,180	26,508
Basic net income per common unit	$ 1.48	$ 1.77	$ 1.20
Diluted net income per common unit**	$ 1.36	$ 1.75	$ 1.15

** Our potentially dilutive common equity includes the following:

	Year Ended December 31,		
	2007	2006	2005
	(In thousands)		
Employee options	537	318	183
Restricted units	138	110	—
Class C units	743	—	—
Class D units	658	—	—
Class E units	1,135	—	—

Share-Based Payment

On January 1, 2006, we adopted SFAS No. 123 (revised 2004), or SFAS No. 123(R), *"Share-Based Payment,"* which establishes accounting standards for all transactions in which an entity exchanges its equity instruments for goods or services. SFAS No. 123(R) focuses primarily on accounting for transactions with employees and does not change prior guidance for share-based payments in transactions with non-employees. SFAS No. 123(R) eliminates the intrinsic value measurement objective in Accounting Principles Board Opinion ("APB") No. 25, *"Accounting for Stock Issued to Employees,"* and generally requires a company to measure the cost of employee services received in exchange for an award of equity instruments based on the fair value of the award on the date of the grant.

The standard requires grant date fair value to be estimated using either an option-pricing model that is consistent with the terms of the award or a market observed price, if such a price exists. Such cost must be recognized over the period during which an employee is required to provide services in exchange for the award (which is usually the vesting period). The standard also requires us to estimate anticipated forfeitures and the number of instruments that will ultimately be issued, rather than accounting for forfeitures as they occur. We began applying SFAS No. 123(R) to all equity awards as of January 1, 2006.

Note 2 — Summary of Significant Accounting Policies (Continued)

We have elected to use the modified prospective method. Under the modified prospective method, we recognize compensation cost for all awards granted beginning January 1, 2006 and for the unvested portions of previously granted awards that are outstanding on that date. Results for prior periods were not restated. Prior to the adoption of SFAS No. 123(R), we recognized equity-based compensation expense for awards with graded vesting by treating each vesting tranche as a separate award and recognizing compensation expense ratably for each tranche. For equity awards outstanding as of January 1, 2006, the remaining unrecognized compensation expense as of January 1, 2006 is expensed on a straight-line basis (net of estimated forfeitures) over the remaining vesting period of the award. We treat equity awards granted after the adoption of SFAS No. 123(R), as a single award and recognize equity-based compensation expense on a straight-line basis (net of estimated forfeitures) over the employee service or vesting period. Equity-based compensation expense is recorded in operations and maintenance expenses and general and administrative expenses in our consolidated statements of operations. See Note 8.

Note 3 — New Accounting Pronouncements

Business Combinations

In December 2007, FASB issued SFAS No. 141 (Revised), "*Business Combinations*" ("SFAS No. 141(R)"). We have not completed our assessment of the impact, if any, of our adoption of SFAS No. 141(R). SFAS No. 141(R) is effective for fiscal years beginning after November 15, 2008.

Fair Value Measurements

In September 2006, the FASB issued SFAS No. 157, "*Fair Value Measurements.*" SFAS No. 157 establishes a framework for measuring fair values under generally accepted accounting principles and applies to other pronouncements that either permit or require fair value measurement, including SFAS No. 133, "*Accounting for Derivative Instruments and Hedging Activities,*" as amended and interpreted. The standard is effective for reporting periods beginning after November 15, 2007. We adopted this statement beginning January 1, 2008, and the adoption did not have a material impact on our consolidated cash flows, results of operations or financial position.

Fair Value Option for Financial Assets and Financial Liabilities

In February 2007, the FASB issued SFAS No. 159, *"The Fair Value Option for Financial Assets and Financial Liabilities,"* which permits entities to choose to measure many financial instruments and certain other items at fair value. SFAS No. 159 is effective for us as of January 1, 2008 and will have no impact on amounts presented for periods prior to the effective date. We adopted this statement beginning January 1, 2008, and the adoption did not have a material impact on our consolidated cash flows, results of operations or financial position. We have chosen not to measure items subject to SFAS No. 159 at fair value.

Non-Controlling Interests in Consolidated Financial Statements — an Amendment of ARB No. 51

In December 2007, the FASB issued SFAS No. 160, "*Non-Controlling Interests in Consolidated Financial Statements — an Amendment of ARB No. 51"* ("SFAS No. 160"). We are currently evaluating the impact that SFAS No. 160 might have on our financial statements upon adoption. SFAS No. 160 is effective for fiscal years beginning after November 15, 2008.

Note 4 — Acquisitions

Acquisition of Cantera Natural Gas, LLC

We acquired all of the membership interests in Cantera Natural Gas, LLC ("Cantera") on October 1, 2007, and closed the acquisition October 19, 2007, pursuant to a Purchase Agreement, dated August 31, 2007, among Copano,

Note 4 — Acquisitions (Continued)

Copano Energy/Rocky Mountains, L.L.C. and Cantera Resources Holdings LLC (the "Cantera Acquisition") for $732.8 million in cash and securities (the "Consideration"). The Consideration consisted of $620.3 million in cash (including $57.8 million of estimated net working capital and other closing adjustments) and 3,245,817 Copano Class D units issued to the seller. We funded the cash portion of the Consideration through a private placement of $335 million in equity securities pursuant to a Class E and Common Unit Purchase Agreement, dated August 31, 2007 with a group of accredited investors (the "Unit Purchase Agreement"), discussed in Note 8, and borrowings of $270 million under the Credit Facility (Note 7).

Cantera's assets consist primarily of 51.0% and 37.04% managing member interests, respectively, in Bighorn and Fort Union, two firm gathering agreements with Fort Union and two firm capacity transportation agreements with Wyoming Interstate Gas Company. Bighorn and Fort Union operate natural gas gathering systems in Wyoming's Powder River Basin. The Bighorn system delivers natural gas into the Fort Union system.

The following is an estimate of the purchase price for the Cantera Acquisition (in thousands):

Purchase price for the Cantera Acquisition	$675,000
Net working capital adjustments	45,762
Acquisition costs	12,013
Total purchase price for the Cantera Acquisition	$732,775

Our management has prepared a preliminary assessment of the fair value of the property, plant and equipment, investments in unconsolidated subsidiaries and intangible assets of Cantera. Using the assessment, the purchase price has been allocated as presented below (in thousands). We do not anticipate any material adjustments to this preliminary purchase price allocation.

Cash and cash equivalents	$ 37,175
Accounts receivable	14,149
Prepayments and other current assets	117
Property, plant and equipment	13,551
Intangibles	62,512
Other assets	81
Investment in unconsolidated affiliates	613,448
Accounts payable	(4,289)
Other current liabilities	(3,812)
Other noncurrent liabilities	(157)
	$732,775

All liabilities assumed were at their fair values. The fair value of intangibles of $62,757,000 relates to contracts with an estimated weighted average amortization period of 25 years. No identified intangibles were determined to have indefinite lives. See Note 2.

Note 4 — Acquisitions (Continued)

Acquisition of Cimmarron Gathering, LP

On May 1, 2007, we acquired all of the partnership interests in Cimmarron Gathering, LP ("Cimmarron"), a Texas limited partnership, for approximately $97.2 million, including working capital and other closing adjustments in cash and securities (the "Initial Cimmarron Acquisition"). The consideration consisted of $43.2 million of cash and 1,579,409 Class C units valued at approximately $54.0 million as described below. The cash portion of the consideration was funded with borrowings under our Credit Facility discussed in Note 7. As a result of the Initial Cimmarron Acquisition, we acquired interests in natural gas and crude oil pipelines in central and eastern Oklahoma and in north Texas, including Cimmarron's 70% undivided interest in the Tri-County gathering system located in north Texas (the "Tri-County System").

Additionally, in June 2007, we closed our acquisition of the remaining 30% interest in the Tri-County System for $15.3 million in cash (the "Additional Cimmarron Acquisition" and together with the Initial Cimmarron Acquisition, the "Cimmarron Acquisition").

The following is an estimate of the purchase price for the Cimmarron Acquisition (in thousands):

Purchase price for the Cimmarron Acquisition	$110,000
Net working capital adjustments	973
Acquisition costs	1,494
Total purchase price for the Cimmarron Acquisition	$112,467

Our management has prepared a preliminary assessment of the fair value of the property, plant and equipment and intangible assets of the Cimmarron Acquisition. Using the preliminary assessment, the purchase price has been allocated as presented below (in thousands). We do not anticipate any material adjustments to this preliminary purchase price allocation.

Cash and cash equivalents	$ 3,257
Accounts receivable	11,027
Prepayments and other current assets	393
Property, plant and equipment	62,558
Intangibles	48,339
Other assets	995
Investment in unconsolidated affiliates	77
Accounts payable	(14,179)
	$112,467

All liabilities assumed were at their fair values. The fair value of intangibles is estimated to be $48,339,000, which includes $41,414,000 of rights-of-way and easements with a weighted average amortization period of 30 years and $6,925,000 of contracts with an estimated weighted average amortization period of 15 years. No identified intangibles were determined to have indefinite lives. See Note 2.

The following table presents selected unaudited pro forma financial information incorporating the historical (pre-acquisition) results of Cantera and Cimmarron as if these acquisitions had occurred at the beginning of each of the periods presented as opposed to the actual date that the acquisition occurred. The pro forma information includes certain estimates and assumptions made by our management. As a result, this pro forma information is not necessarily indicative of our financial results had the transactions actually occurred at the beginning of each of the

Note 4 — Acquisitions (Continued)

periods presents. Likewise, the following unaudited pro forma financial information is not necessarily indicative of our future financial results.

	Year Ended December 31,	
	2007	2006
	(In thousands, except per unit information)	
Pro Forma Earnings Data:		
Revenue	$1,308,916	$1,179,073
Costs and expenses	$1,205,552	$1,082,054
Equity in earnings from unconsolidated affiliates	$ 3,134	$ 2,412
Operating income	$ 103,364	$ 97,019
Income before extraordinary items	$ 54,427	$ 45,850
Net income	$ 54,427	$ 45,850
Basic net income per unit:		
As reported units outstanding	42,456	29,752
Pro forma units outstanding	46,301	34,581
As reported net income per unit	$ 1.48	$ 1.77
Pro forma net income per unit	$ 1.17	$ 1.10
Diluted net income per unit:		
As reported units outstanding	46,516	30,180
Pro forma units outstanding	57,659	44,886
As reported net income per unit	$ 1.36	$ 1.75
Pro forma net income per unit	$ 0.94	$ 0.84
Basic net income per subordinated unit:		
As reported units outstanding	848	7,038
Pro forma units outstanding	848	7,038
As reported net income per unit	$ 0.21	$ 1.77
Pro forma net income per unit	$ 0.21	$ 1.10
Diluted net income per subordinated unit:		
As reported units outstanding	848	7,038
Pro forma units outstanding	848	7,038
As reported net income per unit	$ 0.21	$ 1.76
Pro forma net income per unit	$ 0.21	$ 1.10

Acquisition of ScissorTail Energy, LLC

On August 1, 2005, we completed our acquisition of all of the membership interests in Tulsa-based ScissorTail Energy, LLC (“ScissorTail”) for $499,135,000 (the “ScissorTail Acquisition”). The results of operations for ScissorTail are included in our results beginning August 1, 2005. ScissorTail provides natural gas midstream services in central and eastern Oklahoma and its assets primarily consist of gathering pipelines and three processing plants. In connection with the ScissorTail Acquisition, we operate and hold a majority interest in Southern Dome in partnership with the prior ScissorTail ownership group. Southern Dome was formed to engage in the midstream gas gathering and processing business and related operations in Oklahoma County, Oklahoma and owns the Southern Dome plant, which became operational in April 2006.

Note 5 — Property, Plant and Equipment and Asset Retirement Obligations

Property, plant and equipment consisted of the following (in thousands):

	December 31, 2007	December 31, 2006
Property, plant and equipment, at cost		
Pipelines and equipment	$647,188	$531,509
Gas processing plant and equipment	96,448	77,556
Construction in progress	42,452	18,386
Office furniture and equipment	5,203	4,902
	791,291	632,353
Less accumulated depreciation and amortization	(96,564)	(65,426)
Property, plant and equipment, net	$694,727	$566,927

Asset retirement obligations. We have recorded asset retirement obligations related to those (i) rights-of-way and easements over property we do not own and (ii) regulatory requirements where a legal or contractual obligation exists upon abandonment of the related facility. In December 2005, we adopted FIN 47 and recorded a $215,000 liability in connection with conditional asset retirement obligations. The cumulative effect of this change in accounting principle for years prior to 2005 was not significant. None of our assets is legally restricted for purposes of settling asset retirement obligations.

The following table presents information regarding our asset retirement obligations (in thousands):

Asset retirement obligation liability balance, December 31, 2005	$215
Asset retirement obligations incurred in 2006	106
Accretion of FIN 47 for conditional obligations	19
Asset retirement obligation liability balance, December 31, 2006	340
Asset retirement obligations incurred in 2007	188
Accretion of FIN 47 for conditional obligations	27
Asset retirement obligation liability balance, December 31, 2007	$555

Property and equipment at December 31, 2007, 2006 and 2005 includes $413,000, $225,000 and $119,000, respectively, of asset retirement costs capitalized as an increase in the associated long-lived asset. Also, based on information currently available, we estimate that accretion expense will approximate $37,000 for 2008, $39,000 for 2009, $42,000 for 2010, $44,000 for 2011 and $47,000 for 2012.

Certain of our unconsolidated affiliates have AROs recorded as of December 31, 2007, 2006 and 2005 relating to contractual agreements and regulatory requirements. These amounts are immaterial to our consolidated financial statements.

Note 6 — Investment in Unconsolidated Affiliates

On occasion, the price we pay to acquire an ownership interest in a company or partnership exceeds the underlying book value of the capital accounts we acquire. Such excess cost amounts are included within the carrying values of our investments in unconsolidated affiliates. At December 31, 2007 and 2006, our investments in Webb Duval, Southern Dome, Bighorn and Fort Union included excess cost amounts totaling $546,998,000 and $110,000, respectively, all of which were attributable to the fair value of the underlying tangible and intangible assets of these entities exceeding their book carrying values at the time of our acquisition of interests in these

Note 6 — Investment in Unconsolidated Affiliates (Continued)

entities. To the extent that we attribute all or a portion of an excess cost amount to higher fair values, we amortize such excess cost as a reduction in equity earnings in a manner similar to depreciation. Amortization of such excess cost amounts was $4,589,000, $(14,000) and $(21,000) for the years ended December 31, 2007, 2006 and 2005, respectively.

No restrictions exist under Webb Duval's, Southern Dome's, Bighorn's or Fort Union's partnership or operating agreements that limit these entities' ability to pay distributions to their respective partners or members after consideration of their respective current and anticipated cash needs, including debt service obligations.

Webb Duval

Through our Texas segment, we own a 62.5% general partnership interest in Webb Duval and are the operator of Webb Duval's natural gas gathering systems located in Webb and Duval Counties, Texas. Although we own a majority interest in and operate Webb Duval, we use the equity method of accounting for our investment in Webb Duval because the terms of the general partnership agreement of Webb Duval provide the minority general partners substantive participating rights with respect to the management of Webb Duval. Our investment in Webb Duval totaled $5,135,000 and $6,135,000 as of December 31, 2007 and 2006, respectively.

The summarized financial information for our investment in Webb Duval, which is accounted for using the equity method, is as follows (in thousands):

	Year Ended December 31,		
	2007	2006	2005
Operating revenue	$3,802	$ 5,961	$ 6,809
Operating expenses	(826)	(3,733)	(4,837)
Depreciation	(768)	(743)	(702)
Net income	2,208	1,485	1,270
Ownership %	62.5%	62.5%	62.5%
	1,380	928	793
Copano's share of management fee charged to Webb Duval	132	120	120
Amortization of difference between the carried investment and the underlying equity in net assets	21	21	21
Equity in earnings from Webb Duval	$1,533	$ 1,069	$ 934
Distributions from Webb Duval	$2,401	$ —	$ —
Current assets	$1,920	$ 4,595	
Noncurrent assets	7,426	8,104	
Current liabilities	(779)	(2,502)	
Noncurrent liabilities	(51)	(47)	
Net assets	$8,516	$10,150	

Southern Dome

We, through ScissorTail, operate and hold a majority interest in Southern Dome in partnership with the prior ScissorTail ownership group. Southern Dome was formed to engage in the midstream gas gathering and processing business and related operations in Oklahoma County, Oklahoma and owns the Southern Dome plant, which became operational in April 2006. Although we own a majority interest in Southern Dome, we account for our investment

Note 6 — Investment in Unconsolidated Affiliates (Continued)

using the equity method of accounting because the minority members have substantive participating rights with respect to the management of Southern Dome. The investment in Southern Dome totaled $12,489,000 and $13,243,000 as of December 31, 2007 and 2006, respectively.

The summarized financial information for our investment in Southern Dome, which is accounted for using the equity method, is as follows (in thousands):

	Year Ended December 31,		
	2007	2006	2005
Operating revenue	$ 16,198	$ 6,105	$ 1,289
Operating expenses	(13,683)	(5,468)	(1,296)
Depreciation	(736)	(497)	(3)
Net income	1,779	140	(10)
Ownership %(1)	69.5%	69.5%	69.5%
	1,236	97	(7)
Copano's share of management fee charged to Southern Dome	173	137	—
Amortization of difference between the carried investment and the underlying equity in net assets	(9)	(6)	—
Equity in earnings from Southern Dome	$ 1,400	$ 228	$ (7)
Distributions from Southern Dome	$ 1,981	$ —	$ —
Current assets	$ 4,434	$ 2,516	
Noncurrent assets	16,802	17,507	
Current liabilities	(4,473)	(2,189)	
Net assets	$ 16,763	$17,834	

(1) Represents Copano's right to distributions from Southern Dome.

Bighorn Gas Gathering and Fort Union Gas Gathering

As a result of the Cantera Acquisition and through our Rocky Mountains segment, we hold managing member interests of 51.0% and 37.04% in Bighorn and Fort Union, respectively. Bighorn and Fort Union operate natural gas pipeline systems in Wyoming's Powder River Basin. The Bighorn system delivers natural gas into the Fort Union system.

Although we own a majority managing member interest in Bighorn, we account for our investment using the equity method of accounting because the minority members have substantive participating rights with respect to the management of Bighorn. Our investments in Bighorn and Fort Union totaled $407,881,000 and $207,382,000, respectively, as of December 31, 2007.

Note 6 — Investment in Unconsolidated Affiliates (Continued)

The summarized financial information for our investments in Bighorn and Fort Union, which are accounted for using the equity method, is as follows (in thousands):

	Period from October 1, 2007 Through December 31, 2007	
	Bighorn	Fort Union
Operating revenue	$ 7,809	$ 9,065
Operating expenses	(2,687)	(864)
Depreciation	(994)	(895)
Interest expense and other	24	(1,124)
Net income	4,152	6,182
Ownership %	51%	37.04%
	2,118	2,290
Copano's share of management fee charged to Bighorn and Fort Union	58	8
Amortization of difference between the carried investment and the underlying equity in net assets	(2,995)	(1,606)
Equity in (loss) earnings	$ (819)	$ 692
Distributions	$ 2,624	$ 1,704
Current assets	$ 6,981	$ 12,812
Noncurrent assets	97,570	141,430
Current liabilities	(1,923)	(22,895)
Noncurrent liabilities	—	(87,357)
Net assets	$102,628	$ 43,990

Note 7 — Long-Term Debt

A summary of our debt follows (in thousands):

	December 31,	
	2007	2006
Long-term debt:		
Credit Facility	$280,000	$ 30,000
Senior Notes:		
8.125% senior notes due 2016	350,000	225,000
Unamortized bond premium	773	—
Total Senior Notes	350,773	225,000
Total	$630,773	$255,000

Senior Secured Revolving Credit Facility

Our senior secured revolving credit facility (the "Credit Facility") is provided by Bank of America, N.A., as Administrative Agent, and a group of financial institutions, as lenders, and was established in August 2005. Our obligations under the Credit Facility are secured by first priority liens on substantially all of our assets and substantially all of the assets of our wholly owned subsidiaries (except for certain equity interests we acquired

Note 7 — Long-Term Debt (Continued)

through our acquisitions of Cimmarron and Cantera all of which are party to the Credit Facility as guarantors. Our less-than-wholly owned subsidiaries have not pledged their assets to secure the Credit Facility and do not guarantee obligations under the Credit Facility.

In January 2007, we modified the Credit Facility to, among others things, extend its maturity date to April 15, 2012, revise the interest rate provisions and the commitment fee provisions, increase the maximum ratio of our total debt to EBITDA (as defined under the Credit Facility) permitted under the Credit Facility and eliminate (i) the limitation on our use of borrowings under the Credit Facility to make certain types of capital expenditures, (ii) the maximum consolidated fixed charge coverage ratio (EBITDA minus maintenance capital expenditures to consolidated fixed charges as defined under the Credit Facility) covenant and (iii) the maximum consolidated senior leverage ratio (total senior debt to EBITDA as defined under the Credit Facility).

On October 19, 2007, in connection with the Cantera Acquisition discussed in Note 4, we further amended our Credit Facility to increase the aggregate borrowing capacity under the Credit Facility from $200 million to $550 million; extend the maturity date to October 18, 2012; revise the interest rate and commitment fee provisions; revise certain covenants to accommodate our obligations as managing member of each of Bighorn and Fort Union and to accommodate previously existing obligations of each entity; provide for swing line borrowings in addition to committed borrowings; revise the minimum consolidated interest coverage ratio from 3.0:1 to 2.5:1; and increase the sublimit for the issuance of standby letters of credit from $25 million to $50 million.

Future borrowings under the Credit Facility are available for acquisitions, capital expenditures, working capital and general corporate purposes. The Credit Facility does not provide for the type of working capital borrowings that would be eligible, pursuant to our limited liability company agreement, to be considered cash available for distribution to our unitholders. The Credit Facility is available to be drawn on and repaid without restriction so long as we are in compliance with the terms of the Credit Facility, including certain financial covenants.

Annual interest under the Credit Facility is determined, at our election, by reference to (i) the British Bankers Association LIBOR rate, or LIBOR, plus an applicable margin ranging from 1.25% to 2.50% or (ii) the higher of the federal funds rate plus 0.5% or the prime rate plus, in either case, an applicable margin ranging from 0.25% to 1.50%. Interest is payable quarterly for prime rate loans and at the applicable maturity date for LIBOR loans, except that if the interest period for a LIBOR loan is six months, interest will be paid at the end of each three-month period. The effective average interest rate on borrowings under the Credit Facility for the years ended December 31, 2007, 2006 and 2005 was 6.9%, 7.4% and 6.15%, respectively, and the quarterly commitment fee on the unused portion of the Credit Facility for those periods, respectively, was 0.20%, 0.25% and 0.25%. Interest and other financing costs related to the Credit Facility totaled $10,205,000 and $12,490,000 for the years ended December 31, 2007 and 2006, respectively. Interest and other financing costs for the year ended December 31, 2006 included a one-time charge of $1,702,000 related to the reduction of the commitment under the Credit Facility from $350 million to $200 million. Interest and other financing costs related to the Credit Facility totaled $6,572,000 for the period from August 1, 2005 through December 31, 2005. Costs incurred in connection with the establishment of this credit facility are being amortized over the term of the Credit Facility and, as of December 31, 2007 and 2006, the unamortized portion of debt issue costs totaled $10,261,000 and $2,122,000, respectively.

The Credit Facility, as amended and restated, contains various covenants that, subject to exceptions, limit our and subsidiary guarantors' ability to grant liens; make loans and investments; make distributions other than from available cash (as defined in our limited liability company agreement); merge or consolidate with or into a third party; or engage in certain asset dispositions, including a sale of all or substantially all of our assets. Additionally, the Credit Facility limits us and our subsidiary guarantors' ability to incur additional indebtedness, subject to exceptions, including (i) purchase money indebtedness and indebtedness related to capital or synthetic leases,

Note 7 — Long-Term Debt (Continued)

(ii) unsecured indebtedness qualifying as subordinated debt and (iii) certain privately placed or public term unsecured indebtedness.

The Credit Facility also contains covenants, which, among other things, require us and our subsidiary guarantors, on a consolidated basis, to maintain specified ratios or conditions as follows:

- EBITDA to interest expense of not less than 2.5 to 1.0;
- total debt to EBITDA of not more than 5.0 to 1.0 (with no future reductions) with the option to increase the total debt to EBITDA ratio to not more than 5.5 to 1.0 for a period of up to nine months following an acquisition or a series of acquisitions totaling $50 million in a 12-month period (subject to an increased applicable interest rate margin and commitment fee rate).

EBITDA for the purposes of the Credit Facility is our EBITDA with certain negotiated adjustments.

Based upon the total debt to EBITDA ratio calculated as of December 31, 2007 (utilizing trailing four quarters' EBITDA as defined under the Credit Facility), we have approximately $270.0 million of unused capacity under the Credit Facility.

If an event of default exists under the Credit Facility, the lenders may accelerate the maturity of the obligations outstanding under the Credit Facility and exercise other rights and remedies. Each of the following would be an event of default:

- failure to pay any principal when due or any interest, fees or other amount within specified grace periods;
- failure to perform or otherwise comply with the covenants in the credit agreement or other loan documents, subject to certain grace periods in some cases;
- default on the payment of any other indebtedness in excess of $5 million, or in the performance of any obligation or condition with respect to such indebtedness, beyond the applicable grace period if the effect of the default is to permit or cause the acceleration of the indebtedness;
- bankruptcy or insolvency events involving us or our subsidiaries;
- if Bighorn or Fort Union is unable to make a quarterly distribution to its members, our inability to demonstrate compliance with financial covenants within a specified period;
- the entry of, and failure to pay, one or more adverse judgments in excess of $5 million upon which enforcement proceedings are brought or are not stayed pending appeal; and
- a change of control (as defined in the Credit Facility).

Our management believes that we are in compliance with the covenants under the Credit Facility as of December 31, 2007.

Senior Notes

In February 2006, we issued $225 million in aggregate principal amount of our 8.125% senior notes due 2016 (the "Senior Notes") in a private placement.

In November, 2007, we closed an underwritten public offering of an additional $125 million in aggregate principal amount of our Senior Notes. The additional Senior Notes priced above par, resulting in a $781,000 bond premium that is being amortized over the remaining term of the Senior Notes. The additional Senior Notes were offered under our effective shelf registration statement and constitute an additional issuance under the indenture governing the Senior Notes. We used the net proceeds, after deducting initial purchaser discounts and offering costs of $1,250,000, to reduce the balance outstanding under our Credit Facility.

Note 7 — Long-Term Debt (Continued)

Interest and other financing costs related to the Senior Notes totaled $20,195,000 and $17,091,000 for the years ended December 31, 2007 and 2006, respectively. Costs incurred in connection with the issuance of the Senior Notes are being amortized over the term of the Senior Notes and, as of December 31, 2007, the unamortized portion of debt issue costs totaled $7,328,000.

The Senior Notes represent our senior unsecured obligations and rank pari passu in right of payment with all our other present and future senior indebtedness. The Senior Notes are effectively subordinated to all of our secured indebtedness to the extent of the value of the assets securing the indebtedness and to all existing and future indebtedness and liabilities, including trade payables, of our non-guarantor subsidiaries (other than indebtedness and other liabilities owed to us, if any). The Senior Notes rank senior in right of payment to all of our future subordinated indebtedness.

The Senior Notes are jointly and severally guaranteed by all of our wholly owned subsidiaries (other than CEFC, the co-issuer of the Senior Notes). The subsidiary guarantees rank equally in right of payment with all of the existing and future senior indebtedness of our guarantor subsidiaries, including their guarantees of our other senior indebtedness. The subsidiary guarantees are effectively subordinated to all existing and future secured indebtedness of our subsidiary guarantors (including under our Credit Facility) to the extent of the value of the assets securing that indebtedness, and to all existing and future indebtedness and other liabilities, including trade payables, of any non-guarantor subsidiaries (other than indebtedness and other liabilities owed to our guarantor subsidiaries). The subsidiary guarantees rank senior in right of payment to any future subordinated indebtedness of our guarantor subsidiaries.

Before March 1, 2009, we may, at any time or from time to time, use net proceeds from a public or private equity offering to redeem up to 35% of the aggregate principal amount of the Senior Notes at a redemption price of 108.125% of the principal amount of the Senior Notes, plus any accrued and unpaid interest, so long as at least 65% of the aggregate principal amount of the Senior Notes remains outstanding after such redemption and the redemption occurs within 120 days of the date of the closing of such equity offering.

The Senior Notes are redeemable in whole or in part, at our option, at any time on or after March 1, 2011 and at the redemption prices in the table below, together with any accrued and unpaid interest to the date of redemption.

Year	Percentage
2011	104.0625%
2012	102.7083%
2013	101.3542%
2014 and thereafter	100.0000%

Prior to March 1, 2011, we may redeem the Senior Notes, in whole or in part, at a “make-whole” redemption price together with any accrued and unpaid interest to the date of redemption.

The indenture governing the Senior Notes includes covenants that limit our and our subsidiary guarantors’ ability to, among other things:

- sell assets;
- pay distributions on, redeem or repurchase our units, or redeem or repurchase our subordinated debt;
- make investments;
- incur or guarantee additional indebtedness or issue preferred units;
- create or incur liens;
- enter into agreements that restrict distributions or other payments from our restricted subsidiaries to us;

Note 7 — Long-Term Debt (Continued)

- consolidate, merge or transfer all or substantially all of our assets;
- engage in transactions with affiliates;
- create unrestricted subsidiaries; and
- enter into sale and leaseback transactions.

These covenants are subject to customary exceptions and qualifications. Additionally, if the Senior Notes achieve an investment grade rating from each of Moody's Investors Service and Standard & Poor's Ratings Services, many of these covenants will terminate. Our management believes that we are in compliance with the covenants under the Senior Notes indenture as of December 31, 2007.

Condensed consolidating financial information for Copano and our wholly owned subsidiaries is presented below.

Note 7 — Long-Term Debt (Continued)

CONDENSED CONSOLIDATING BALANCE SHEETS

	December 31, 2007						December 31, 2006					
	Parent	Co-Issuer	Guarantor Subsidiaries	Investment in Non-Guarantor Subsidiaries	Eliminations	Total	Parent	Co-Issuer	Guarantor Subsidiaries	Investment in Non-Guarantor Subsidiaries	Eliminations	Total
	(In thousands)											
ASSETS												
Current assets:												
Cash and cash equivalents	$ 10,018	$—	$ 62,647	$ —	$ —	$ 72,665	$ 1,286	$—	$ 38,198	$ —	$ —	$ 39,484
Accounts receivable, net	476	—	127,058	—	—	127,534	32	—	120,057	—	(52,994)	67,095
Intercompany receivable	37,027	—	(37,027)	—	—	—	24,908	—	(71,028)	—	46,120	—
Risk management assets	—	—	3,289	—	—	3,289	—	—	13,973	—	—	13,973
Prepayments and other current assets	877	—	3,004	—	—	3,881	44	—	3,122	—	—	3,166
Total current assets	48,398	—	158,971	—	—	207,369	26,270	—	104,322	—	(6,874)	123,718
Property, plant and equipment, net	264	—	694,463	—	—	694,727	299	—	566,628	—		566,927
Intangible assets, net	—	—	200,546	—	—	200,546	—	—	93,372	—	—	93,372
Investment in unconsolidated affiliates	—	—	632,725	632,725	(632,725)	632,725	—	—	19,378	19,378	(19,378)	19,378
Investment in consolidated subsidiaries	1,473,187	—	—	—	(1,473,187)	—	674,105	—	—	—	(674,105)	—
Risk management assets	—	—	10,598	—	—	10,598	—	—	23,826	—	—	23,826
Other assets, net	17,589	—	5,529	—	—	23,118	8,577	—	3,260	—	—	11,837
Total assets	$1,539,438	$—	$1,702,832	$632,725	$(2,105,912)	$1,769,083	$709,251	$—	$810,786	$19,378	$(700,357)	$839,058
LIABILITIES AND MEMBERS'/PARTNERS' CAPITAL												
Current liabilities:												
Accounts payable	$ 35	$—	$ 147,011	$ —	$ ()	$ 147,046	$ 434	$—	$130,919	$ —	$ (39,685)	$ 91,668
Intercompany payable	—	—	—	—	—	—	(26,291)	—	(6,520)	—	32,811	—
Notes payable	—	—	—	—	—	—	—	—	1,495	—	—	1,495
Accrued interest	11,319	—	—	—	—	11,319	6,261	—	—	—	—	6,261
Accrued tax liability	483	—	3,436	—	—	3,919	—	—	—	—	—	—
Risk management liabilities	—	—	27,710	—	—	27,710	—	—	944	—	—	944
Other current liabilities	882	—	12,049	—	—	12,931	550	—	4,804	—	—	5,354
Total current liabilities	12,719	—	190,206	—	—	202,925	(19,046)	—	131,642	—	(6,874)	105,722
Long-term debt	630,773	—	—	—	—	630,773	255,000	—	—	—	—	255,000
Deferred tax provision	1,231	—	—	—	—	1,231	—	—	—	—	—	—
Risk management and other noncurrent liabilities	579	—	39,439	—	—	40,018	711	—	5,039	—	—	5,750
Members'/Partners' capital:												
Common units	661,585	—	—	—	—	661,585	480,797	—	—	—	—	480,797
Class C units	40,492	—	—	—	—	40,492						
Class D units	112,454	—	—	—	—	112,454						
Class E units	175,634	—	—	—	—	175,634						
Subordinated units	—	—	—	—	—	—	10,379	—	—	—	—	10,379
Paid-in capital	23,773	1	1,507,285	628,375	(2,135,661)	23,773	10,585	1	524,940	17,445	(542,386)	10,585
Accumulated (deficit) earnings	(7,867)	(1)	77,837	4,350	(82,186)	(7,867)	2,918	(1)	181,258	1,933	(183,190)	2,918
Deferred compensation	—	—	—	—	—	—	—	—	—	—	—	—
Other comprehensive loss	(111,935)	—	(111,935)	—	111,935	(111,935)	(32,093)	—	(32,093)	—	32,093	(32,093)
	894,136	—	1,473,187	632,725	(2,105,912)	894,136	472,586	—	674,105	19,378	(693,483)	472,586
Total liabilities and members'/partners' capital	$1,539,438	$—	$1,702,832	$632,725	$(2,105,912)	$1,769,083	$709,251	$—	$810,786	$19,378	$(700,357)	$839,058

COPANO ENERGY, L.L.C. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Note 7 — Long-Term Debt (Continued)

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS

	For the Year Ended December 31, 2007						For the Year Ended December 31, 2006					
	Parent	Co-Issuer	Guarantor Subsidiaries	Investment in Non-Guarantor Subsidiaries	Eliminations	Total	Parent	Co-Issuer	Guarantor Subsidiaries	Investment in Non-Guarantor Subsidiaries	Eliminations	Total
	(In thousands)											
Revenue:												
Natural gas sales	$ —	$—	$ 518,431	$ —	$ —	$ 518,431	$ —	$—	$448,054	$ —	$ —	$448,054
Natural gas liquids sales	—	—	491,432	—	—	491,432	—	—	369,892	—	—	369,892
Crude oil sale	—	—	77,142	—	—	77,142	—	—	—	—	—	—
Transportation, compression and processing fees	—	—	22,306	—	—	22,306	—	—	16,232	—	—	16,232
Condensate and other	—	—	32,349	—	—	32,349	—	—	26,094	—	—	26,094
Total revenue	—	—	1,141,660	—	—	1,141,660	—	—	860,272	—	—	860,272
Costs and expenses:												
Cost of natural gas and natural gas liquids	—	—	853,964	—	—	853,964	—	—	669,158	—	—	669,158
Cost of crude oil	—	—	73,814	—	—	73,814						
Transportation	—	—	6,948	—	—	6,948	—	—	3,026	—	—	3,026
Operations and maintenance	1,764	—	39,392	—	—	41,156	917	—	31,567	—	—	32,484
Depreciation and amortization	34	—	39,933	—	—	39,967	66	—	31,927	—	—	31,993
General and administrative	10,848	—	23,790	—	—	34,638	9,296	1	17,238	—	—	26,535
Taxes other than income	—	—	2,637	—	—	2,637	—	—	2,061	—	—	2,061
Equity in earnings from unconsolidated affiliates	—	—	(2,850)	(2,850)	2,850	(2,850)	—	—	(1,297)	(1,297)	1,297	(1,297)
Total costs and expenses	12,646	—	1,037,628	(2,850)	2,850	1,050,274	10,279	1	753,680	(1,297)	1,297	763,960
Operating (loss) income	(12,646)	—	104,032	2,850	(2,850)	91,386	(10,279)	(1)	106,592	1,297	(1,297)	96,312
Other income (expense):												
Interest and other income	247	—	2,607	—	—	2,854	—	—	1,706	—	—	1,706
Interest and other financing costs	(29,467)	—	116	—	—	(29,351)	(33,207)	—	303	—	—	(32,904)
(Loss) income before income taxes and equity in earnings from consolidated subsidiaries	(41,866)	—	106,755	2,850	(2,850)	64,889	(43,486)	(1)	108,601	1,297	(1,297)	65,114
Provision for income taxes	(1,714)	—	—	—	—	(1,714)	—	—	—	—	—	—
(Loss) income before income taxes and equity in earnings from consolidated subsidiaries	(43,580)	—	106,755	2,850	(2,850)	63,175	(43,486)	(1)	108,601	1,297	(1,297)	65,114
Equity in earnings from consolidated subsidiaries	106,755	—	—	—	(106,755)	—	108,600	—	—	—	(108,600)	—
Net income (loss)	$ 63,175	$—	$ 106,755	$ 2,850	$(109,605)	$ 63,175	$ 65,114	$ (1)	$108,601	$ 1,297	$(109,897)	$ 65,114

Note 7 — Long-Term Debt (Continued)

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS

	For the Year Ended December 31, 2005					
	Parent	Co-Issuer	Guarantor Subsidiaries	Investment in Non-Guarantor Subsidiaries	Eliminations	Total
	(In thousands)					
Revenue:						
Natural gas sales	$ —	$—	$496,906	$ —	$ —	$496,906
Natural gas liquids sales	—	—	224,695	—	—	224,695
Transportation, compression and processing fees	—	—	15,110	—	—	15,110
Other	—	—	11,032	—	—	11,032
Total revenue	—	—	747,743	—	—	747,743
Costs and expenses:						
Cost of natural gas and natural gas liquids	—	—	641,315	—	—	641,315
Transportation	—	—	2,337	—	—	2,337
Operations and maintenance	66	—	18,393	—	—	18,459
Depreciation and amortization	66	—	16,986	—	—	17,052
General and administrative	5,486	—	12,670	—	—	18,156
Taxes other than income	—	—	1,178	—	—	1,178
Equity in earnings from unconsolidated affiliates	—	—	(927)	(927)	927	(927)
Total costs and expenses	5,618	—	691,952	(927)	927	697,570
Operating (loss) income	(5,618)	—	55,791	927	(927)	50,173
Other income (expense):						
Interest and other income	3	—	1,023	—	(386)	640
Interest and other financing costs	(16,848)	—	(3,999)	—	386	(20,461)
(Loss) income before equity in earnings from consolidated subsidiaries	(22,463)	—	52,815	927	(927)	30,352
Equity in earnings from consolidated subsidiaries	52,815	—	—	—	(52,815)	—
Net income (loss)	$ 30,352	$—	$ 52,815	$ 927	$(53,742)	$ 30,352

Note 7 — Long-Term Debt (Continued)

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

	For the Year Ended December 31, 2007						For the Year Ended December 31, 2006					
	Parent	Co-Issuer	Guarantor Subsidiaries	Investment in Non-Guarantor Subsidiaries	Eliminations	Total	Parent	Co-Issuer	Guarantor Subsidiaries	Investment in Non-Guarantor Subsidiaries	Eliminations	Total
	(In thousands)											
Cash Flows From Operating Activities:												
Net cash (used in) provided by operating activities	$ (19,109)	$—	$ 147,327	$ 3,706	$ (3,706)	$ 128,218	$(55,791)	$ (1)	$147,471	$ —	$ —	$ 91,679
Cash Flows From Investing Activities:												
Net cash (used in) provided by investing activities	(605,668)	—	(727,052)	(1,051)	606,719	(727,052)	61,269	—	(70,700)	(10,438)	(50,422)	(70,291)
Cash Flows From Financing Activities:												
Net cash provided by (used in) financing activities	633,509	—	604,174	1,727	(607,395)	632,015	(5,359)	—	(62,702)	10,438	50,422	(7,201)
Net increase (decrease) in cash and cash equivalents	8,732	—	24,449	4,382	(4,382)	33,181	119	(1)	14,069	—	—	14,187
Cash and cash equivalents, beginning of year	1,286	—	38,198	—	—	39,484	1,167	1	24,129	—	—	25,297
Cash and cash equivalents, end of year	$ 10,018	$—	$ 62,647	$ 4,382	$ (4,382)	$ 72,665	$ 1,286	$—	$ 38,198	$ —	$ —	$ 39,484

Note 7 — Long-Term Debt (Continued)

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS

	For the Year Ended December 31, 2005					
	Parent	Co-Issuer	Guarantor Subsidiaries	Investment in Non-Guarantor Subsidiaries	Eliminations	Total
	(In thousands)					
Cash Flows From Operating Activities:						
Net cash (used in) provided by operating activities	$ (47,292)	$—	$ 47,572	$ —	$ —	$ 280
Cash Flows From Investing Activities:						
Net cash (used in) provided by investing activities	(500,638)	—	(491,708)	(2,722)	503,360	(491,708)
Cash Flows From Financing Activities:						
Net cash provided by (used in) financing activities	548,973	1	461,374	2,722	(503,360)	509,710
Net increase in cash and cash equivalents	1,043	1	17,238	—	—	18,282
Cash and cash equivalents, beginning of year	124	—	6,891	—	—	7,015
Cash and cash equivalents, end of year	$ 1,167	$ 1	$ 24,129	$ —	$ —	$ 25,297

Note 7 — Long-Term Debt (Continued)

Other Indebtedness

On September 29, 2006, we entered into an unsecured term loan (the "Unsecured Term Loan") with Banc of America Bridge LLC and certain of its affiliates and used the proceeds to reduce outstanding indebtedness under the Credit Facility from $150 million to $50 million as of December 31, 2006. In December 2006, we used proceeds from a public equity offering to repay and terminate the Unsecured Term Loan. Interest and other financing costs related to the Unsecured Term Loan totaled $2,194,000 for the year ended December 31, 2006. Effective with the early termination of this agreement, we charged $588,000 to interest expense, representing the balance of the unamortized debt issue costs.

On August 1, 2005, we entered into a $170 million senior unsecured term loan facility (the "Term Loan Facility") with Banc of America Bridge LLC, as Lender, to finance a portion of the ScissorTail Acquisition. In January 2006, we used proceeds from a private placement of equity (discussed in Note 8) to repay $20 million of the balance outstanding under the Term Loan Facility. We used proceeds from our issuance of Senior Notes in February 2006 to repay and terminate the Term Loan Facility. Interest and other financing costs related to the Term Loan Facility totaled $2,125,000 for the year ended December 31, 2006, including the amortization of debt issue costs of $584,000.

Scheduled Maturities of Long-Term Debt

Scheduled maturities of long-term debt as of December 31, 2007 were as follows (in thousands):

Year	Principal Amount
2007	$ —
2008	—
2009	—
2010	—
2011	—
Thereafter	630,000
	$630,000

Note 8 — Members' Capital

Common Units

On February 15, 2007, our Board of Directors approved a two-for-one split of our outstanding common units. The unit split entitled each unitholder of record at the close of business on March 15, 2007, to receive one additional common unit for every common unit held on that date. The additional common units were distributed to unitholders on March 30, 2007. The unit and per unit information in the accompanying consolidated financial statements and related notes has been adjusted to reflect this two-for-one unit split distributed on March 30, 2007.

On August 1, 2005, we issued 2,744,916 common units in a private placement for aggregate consideration of $39.5 million to finance a portion of the ScissorTail Acquisition and related costs (Note 4). Pursuant to a registration rights agreement among us and the common unit purchasers, we registered unitholder resales of these common units on a Registration Statement on Form S-3, which was declared effective by the Securities and Exchange Commission, or SEC, on January 26, 2006.

On December 29, 2005 and January 3, 2006, we issued 1,418,440 and 1,418,440 common units, respectively, in a private placement for aggregate net proceeds of $50.0 million. We used the proceeds from the private placement

Note 8 — Members' Capital — (Continued)

to reduce balances outstanding under our Credit Facility and our Term Loan Facility discussed in Note 7. Pursuant to a registration rights agreement among us and the common unit purchasers, we registered unitholder resales of these common units on a Registration Statement on Form S-3, which was declared effective by the SEC on April 28, 2006.

On December 6 and December 21, 2006, respectively, we issued 5,000,000 common units in an underwritten public offering and 750,000 common units upon the underwriters' exercise of their option to purchase additional units. We used proceeds from the offering and the over-allotment to repay our $100 million unsecured term loan (Note 7), reduce our Credit Facility by $30 million (Note 7), expand our commodity risk management portfolio (Note 11) and for general company purposes.

On October 19, 2007, we issued 4,533,324 common units in a private placement for aggregate consideration of $157.1 million to finance a portion of the Cantera Acquisition. Pursuant to a registration rights agreement among us and the purchasers, we registered unitholder resales of these units on a Registration Statement on Form S-3/ASR, which became effective upon filing on December 17, 2007.

As of December 31, 2007, we had 47,366,048 common units (excluding restricted units awarded under our LTIP) outstanding. Management controlled an aggregate of 4,482,089 of these common units as of December 31, 2007.

Pursuant to our limited liability company agreement, certain of our investors existing prior to our initial public offering (the "Pre-IPO Investors") agreed to reimburse us for general and administrative expenses in excess of stated levels (subject to certain limitations) for a period of three years beginning on January 1, 2005. Specifically, to the extent general and administrative expenses exceed certain levels, the portion of the general and administrative expenses ultimately funded by us (subject to certain adjustments and exclusions) will be limited, or capped. For the years ended December 31, 2007, 2006 and 2005, the "cap" limits our general and administrative expense obligations to $1.8 million, $1.65 million and $1.5 million per quarter (subject to certain adjustments and exclusions), respectively. During this three-year period, the quarterly limitation on general and administrative expenses was increased by 10% of the amount by which EBITDA (as defined) for any quarter exceeds $5.4 million. The following summarizes capital contributions made to us by our Pre-IPO Investors (in thousands):

	Year Ended December 31,		
Period Cover	**2007**	**2006**	**2005**
January 1, 2005 through September 30, 2005	$ —	$ —	$4,068
October 1, 2005 through September 30, 2006	—	4,607	—
October 1, 2006 through September 30, 2007	9,965	—	—

In February 2008, our Pre-IPO Investors made capital contributions to us in the aggregate amount of $3,935,000 as a reimbursement of excess general and administrative expense for the fourth quarter of 2007.

Class B Units

On August 1, 2005, to finance a portion of the ScissorTail Acquisition, we issued 4,830,758 Class B units, which were convertible into common units, in a private placement for aggregate consideration of $135.5 million. On October 27, 2005, our unitholders approved conversion of each Class B unit into one common unit and the issuance of 4,830,758 additional common units upon such conversion. Pursuant to a registration rights agreement among us and the Class B unit purchasers, we registered unitholder resales of the common units issued upon conversion of the Class B units on a Registration Statement on Form S-3, which was declared effective by the SEC on January 26, 2006.

Note 8 — Members' Capital — (Continued)

Class C Units

On May 1, 2007, as part of the consideration for the Initial Cimmarron Acquisition, we issued in a private placement 1,579,409 Class C units, a new class of equity interests, to the sellers of Cimmarron. The Class C units represented approximately $54.0 million of the acquisition consideration, based on the average closing price of our common units over the ten business days preceding the execution date of the acquisition agreement. Our limited liability agreement provides that up to 25% of the total Class C units issued (less any Class C units released to us in satisfaction of obligations of the sellers pursuant to the arrangement described below) will convert into common units on each of the six-month, 12-month, 18-month and 24-month anniversaries of the closing of the Initial Cimmarron Acquisition. Class C units are not entitled to receive quarterly cash distributions. Otherwise, the Class C units have the same terms and conditions as our common units, including with respect to voting rights. The Class C units are not quoted for trading on The NASDAQ Stock Market LLC or any other securities exchange. On November 1, 2007, 394,852 of the Class C units, or 25% of the total Class C units issued, converted to common units.

At the closing of the Initial Cimmarron Acquisition, 453,838 Class C units otherwise issuable to the sellers of Cimmarron, representing approximately $17.5 million of the acquisition consideration, were deposited into escrow for up to one year to satisfy post-closing claims for indemnification by us, if any, with respect to certain representations and warranties of the Cimmarron sellers (including with respect to title to the Cimmarron partnership interests). The acquisition agreement provides that, at the six-month anniversary of the closing, no such indemnity claims exist, the amount of Class C units held in escrow would be reduced to $5.0 million. On November 1, 2007, the six-month anniversary of the Initial Cimmarron Acquisition, we determined that no indemnity claims existed to be satisfied using the Class C units. Accordingly, on November 19, 2007, the escrow agent released 320,190 Class C units to the Cimmarron sellers, which reduced the number of Class C units in escrow to 133,648, representing $5.0 million.

Pursuant to a registration rights agreement among us and the Cimmarron sellers, we registered unitholder resales of the common units issuable upon conversion of the Class C units on a Registration Statement on Form S-3/ASR, which became effective upon filing December 17, 2007. The Class C units are not quoted for trading on The NASDAQ Stock Market LLC or any other securities exchange.

Class D Units

On October 19, 2007, as part of the Consideration for the Cantera Acquisition, we issued in a private placement 3,245,817 Class D units to the seller of Cantera. The Class D units represented approximately $112.5 million of the Consideration. The Class D units represent a new class of equity interest and are convertible into our common units on a one-for-one basis upon the earlier of (i) payment of our common unit distribution with respect to the fourth quarter of 2009 or (ii) our payment of $6.00 in cumulative distributions per common unit (beginning with our distribution with respect to the fourth quarter of 2007) to common unitholders.

The Class D units are not entitled to receive cash distributions. The Class D units will otherwise have the same terms and conditions as our common units, including with respect to voting rights. The Class D units are not quoted for trading on The NASDAQ Stock Market LLC or any other securities exchange. No vote of our common unitholders will be required to convert the Class D units to common units.

Pursuant to a registration rights agreement among us and the Cantera seller, we are obligated to file a shelf registration statement relating to resales of our common units issued upon conversion of the Class D units within 60 days after the date of conversion.

Note 8 — Members' Capital — (Continued)

Class E Units

On October 19, 2007, as part of our financing for the Cantera Acquisition, we issued 5,598,836 Class E units in a private placement for aggregate proceeds of $177.9 million. The Class E units represent a new class of equity interest and have no voting rights other than as required by law, are subordinate to our common units on dissolution and liquidation and have no distribution rights until our distribution with respect to the fourth quarter of 2008, when the Class E units will become entitled to a special quarterly distribution equal to 110% of the quarterly common unit distribution. The Class E units will convert into common units upon payment of our distribution to common unitholders with respect to the third quarter of 2008, if the conversion terms of the Class E units are approved by our existing common unitholders and our Class C unitholders. Our Board of Directors has convened a special meeting of our unitholders for March 13, 2008 to consider this proposal. The Class E units are not quoted for trading on The NASDAQ Stock Market LLC or any other securities exchange.

Pursuant to a registration rights agreement among us and the Class E unit purchasers, we registered unitholder resales of the Class E units, and of the common units to be issued upon conversion of the Class E units, on a Registration Statement on Form S-3/ASR, which became effective upon filing on December 17, 2007.

Subordinated Units

We issued 7,038,252 subordinated units (as adjusted to reflect the common unit split) to our Pre-IPO Investors at the closing of our IPO. Effective February 14, 2007, all 7,038,252 subordinated units converted on a one-for-one basis into common units as a result of the satisfaction of the financial tests set forth in our limited liability company agreement.

Pursuant to a registration rights agreement among us and the subordinated unitholders, we registered unitholder resales of the common units issued upon conversion of the subordinated units on a Registration Statement on Form S-3/ASR, which became effective upon filing on March 16, 2007.

Distributions

The following table sets forth information regarding distributions to our unitholders for quarterly periods ending after our IPO in November 2004:

Quarter Ending[(a)]	Distribution Per Unit	Date Declared	Record Date	Payment Date	Amount
December 31, 2004	$0.1000[(a)]	January 18, 2005	February 1, 2005	February 14, 2005	$ 2,115,000
March 31, 2005	0.2100	April 18, 2005	May 2, 2005	May 13, 2005	4,450,000
June 30, 2005	0.2250[(b)]	July 15, 2005	August 1, 2005	August 15, 2005	7,819,000
September 30, 2005	0.2500	October 17, 2005	November 1, 2005	November 14, 2005	8,449,000
December 31, 2005	0.2750	January 18, 2006	February 1, 2006	February 14, 2006	10,081,000
March 31, 2006	0.3000	April 18, 2006	May 1, 2006	May 15, 2006	11,000,000
June 30, 2006	0.3375	July 19, 2006	August 1, 2006	August 14, 2006	12,400,000
September 30, 2006	0.3750	October 18, 2006	November 1, 2006	November 14, 2006	13,800,000
December 31, 2006	0.4000	January 18, 2007	February 1, 2007	February 14, 2007	17,025,000
March 31, 2007	0.4200	April 18, 2007	May 1, 2007	May 15, 2007	17,881,000
June 30, 2007	0.4400	July 18, 2007	August 1, 2007	August 14, 2007	18,743,000
September 30, 2007[(c)]	0.4700	October 17, 2007	November 1, 2007	November 14, 2007	20,276,000
December 31, 2007	0.5100	January 16, 2008	February 1, 2008	February 14, 2008	24,336,000

Note 8 — Members' Capital — (Continued)

(a) The distribution for the quarter ended December 31, 2004 reflected a pro rata portion of our $0.20 per unit MQD, covering the period from the November 15, 2004 closing of our initial public offering through December 31, 2004.

(b) Includes a concurrent quarterly distribution of $0.2475 per unit with respect to 9,661,516 Class B units issued in connection with the closing of the ScissorTail Acquisition.

(c) Common units issued on October 19, 2007 were not eligible for this distribution pursuant to the provisions of the Unit Purchase Agreement.

Accounting for Equity-Based Compensation

As discussed in Note 2, on January 1, 2006, we adopted SFAS No. 123(R). Equity-based compensation expense relates to awards issued under our long-term incentive plan, or LTIP, discussed in *"Restricted Common Units," "Phantom Units"* and *"Unit Options"* below. As of December 31, 2007, the number of units available for grant under our long-term incentive plan totaled 5,000,000, of which up to 982,452 units are eligible to be issued as restricted common units or phantom units.

Restricted Common Units. Restricted units are awarded under our LTIP and are common units that vest over time and are subject to forfeiture during such time. In addition, restricted units vest upon a change of control, unless provided otherwise by the Compensation Committee of our Board of Directors, and may vest in other circumstances (for example, death or disability), as approved by our Compensation Committee and reflected in an award agreement. Some restricted common unit award agreements provide that, upon vesting, the Company has the right to deliver an amount of cash equal to the fair market value of the units on the vesting date in lieu of issuing the units. Upon vesting, it is the intention of the Company to issue common units rather than delivering a cash equivalent. Distributions made on restricted units may be subjected to the same vesting provisions as the restricted units. The restricted units are intended to serve as a means of incentive compensation for performance and not primarily as an opportunity to participate in the equity appreciation of the common units. Therefore, plan participants do not pay any consideration for the common units they receive. As of December 31, 2007, 241,181 restricted common units were outstanding.

The aggregate intrinsic value of the restricted common units net of anticipated forfeitures is amortized into expense over the respective vesting periods of the awards. We recognized non-cash compensation expense of $2,125,000, $1,475,000 and $1,283,000 related to the amortization of restricted common units outstanding during the years ended December 31, 2007, 2006 and 2005, respectively.

A summary of restricted unit activity is provided below:

	2007		2006		2005	
	Number of Restricted Units	Weighted Average Grant-Date Fair Value	Number of Restricted Units	Weighted Average Grant-Date Fair Value	Number of Restricted Units	Weighted Average Grant-Date Fair Value
Outstanding at beginning of period	315,936	$20.84	278,236	$18.30	36,000	$12.06
Granted	23,500	37.20	120,540	24.51	258,940	18.87
Vested	(93,742)	19.56	(69,306)	17.38	(12,524)	12.41
Forfeited	(4,513)	21.09	(13,534)	19.01	(4,180)	18.09
Outstanding at end of period	241,181	$22.92	315,936	$20.84	278,236	$18.30

During May 2006, we modified three employee restricted common unit grants totaling 21,702 units, and 12 director restricted common unit grants totaling 42,000 units, to accelerate their respective annual vesting dates by up to two months. These modifications were made to reduce certain of our tax administrative costs.

Note 8 — Members' Capital — (Continued)

SFAS No. 123(R) required us to revalue these restricted common unit grants as of the date of the modification and, as a result, we will recognize an additional $857,000 of compensation expense over the remaining life of these modified awards. For the years ended December 31, 2007 and 2006, we recognized $473,000 and $291,000, respectively, of this increased expense.

As of December 31, 2007 and 2006, unrecognized compensation costs related to outstanding restricted common units totaled $4,347,000 and $5,621,000, respectively. The expense is expected to be recognized over a weighted average period of 3.4 years. The total fair value of restricted common units vested during the years ended December 31, 2007 and 2006 was $3,593,000 and $1,769,000, respectively.

Phantom Units. Phantom units are awarded under our LTIP and, upon vesting, entitle the holder to receive our common units or an equivalent amount of cash, as determined by the Compensation Committee in its discretion. It is the intention of the Compensation Committee to settle vested phantom units by issuing common units (fractional units, if any, would be settled in cash). Generally, phantom units vest over time and are subject to forfeiture. In addition, phantom units vest upon a change of control, unless provided otherwise by the Compensation Committee of our Board of Directors, and may vest in other circumstances (for example, death or disability), as approved by our Compensation Committee and reflected in an award agreement. DERs, or distribution equivalent rights, made on phantom units may be subjected to the same vesting provisions as the phantom units. The phantom units are intended to serve as a means of incentive compensation for performance and not primarily as an opportunity to participate in the equity appreciation of the units. Therefore, plan participants do not pay any cash consideration for the phantom units they receive. As of December 31, 2007, 100,795 phantom units were outstanding. No phantom units were awarded under our LTIP prior to June 12, 2007.

The aggregate intrinsic value of phantom units net of anticipated forfeitures is amortized into expense over the respective vesting periods of the awards. We recognized non-cash compensation expense of $412,000 related to the amortization of phantom units outstanding during the year ended December 31, 2007.

A summary of the phantom unit activity for the year ended December 31, 2007 is provided below:

	Number of Phantom Units	Weighted Average Grant-Date Fair Value
Outstanding at beginning of year	—	$ —
Granted	101,465	40.82
Vested	—	—
Forfeited	(670)	41.74
Outstanding at end of period	100,795	$40.81

As of December 31, 2007, unrecognized compensation expense related to outstanding phantom units totaled $3,702,000. The expense is expected to be recognized over a weighted average period of five years.

Unit Options. Unit options are granted under our LTIP and entitle the holder to purchase our common units at an exercise price that may not be less than the fair market value of the underlying units on the date of grant. In general, unit options become exercisable over a period determined by our Compensation Committee. In addition, unit options become exercisable upon a change in control, unless provided otherwise by our Compensation Committee, and may vest in other circumstances (for example, death or disability), as approved by our Compensation Committee and reflected in an award agreement. Some option award agreements provide that, upon exercise, we have the right to deliver an amount of cash equal to the fair market value of the units on the exercise date over the exercise price of the unit options in lieu of issuing the common units. It is our intention to issue common units rather than delivering a cash equivalent upon the exercise of a unit option. We recognized non-

Note 8 — Members' Capital — (Continued)

cash compensation expense of $685,000 and $435,000 related to the amortization of unit options outstanding during the years ended December 31, 2007 and 2006, respectively.

A summary of unit option activity under our LTIP is provided below:

	2007		2006		2005	
	Number of Units Underlying Options	Weighted Average Exercise Price	Number of Units Underlying Options	Weighted Average Exercise Price	Number of Units Underlying Options	Weighted Average Exercise Price
Outstanding at beginning of period	1,212,506	$17.15	982,220	$15.09	400,000	$10.00
Granted	418,200	37.60	315,490	23.52	618,220	18.26
Exercised	(115,288)	15.72	(30,064)	12.58	(8,880)	10.00
Forfeited	(72,571)	29.92	(55,140)	18.01	(27,120)	13.87
Outstanding at end of period	1,442,847	$22.60	1,212,506	$17.15	982,220	$15.09
Aggregate intrinsic value at end of period	$19,843,000		$15,337,000			
Weighted average remaining contractual term	8.1 years		8.6 years			
Exercisable Options:						
Outstanding at end of period	362,645	$15.43	236,268	$13.81	75,376	$10.20
Aggregate intrinsic value at end of period	$ 7,585,000		$ 3,779,000			
Weighted average remaining contractual term	7.5 years		8.2 years			
Weighted average fair value of option granted		$ 4.33		$ 3.10		$ 2.57
Options expected to vest:						
At end of period	1,298,562	$22.60	1,091,256	$17.15		
Aggregate intrinsic value at end of period	$17,859,000		$13,803,000			
Weighted average remaining contractual term	8.1 year		8.6 years			

Exercise prices for unit options outstanding as of December 31, 2007 ranged from $10.00 to $44.14.

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 assumptions. The risk-free rate of periods within the expected life of the option is based on the U.S. Treasury yield curve in effect at the time of grant. The expected volatility and distribution yield rates are based on the average of our historical unit prices and distribution rates and those of similar companies. The expected term of unit options is based on the simplified method and represents the period of time that unit options granted are expected to be outstanding.

	Year Ended December 31,		
	2007	2006	2005
Weighted average exercise price	$ 37.60	$ 23.52	$ 18.26
Expected volatility	20.6-21.5%	21.3-22.5%	24.5-26.9%
Distribution yield	6.00-6.10%	5.97-6.04%	6.27-6.51%
Risk-free interest rate	3.48-5.11%	4.33-5.14%	3.74-4.59%
Expected term (in years)	6.5	6.5	7
Weighted average grant-date fair value of options granted	$ 4.33	$ 3.10	$ 2.57
Total intrinsic value of options exercised	$2,361,000	$ 412,000	$ 82,000

Note 8 — Members' Capital — (Continued)

As of December 31, 2007 and 2006, unrecognized compensation costs related to outstanding unit options issued under our LTIP totaled $2,805,000 and $1,899,000, respectively. The expense is expected to be recognized over a weighted average period of approximately four years.

Note 9 — Related Party Transactions

Operations Services

Pursuant to our administrative and operating services agreement, as amended, with Copano/Operations, Inc. ("Copano Operations"), Copano Operations provides certain management, operations and administrative support services to us. Copano Operations is controlled by John R. Eckel, Jr., our Chairman of the Board of Directors and Chief Executive Officer. We reimburse Copano Operations for its direct and indirect costs of providing these services. Specifically, Copano Operations charges us, without markup, based upon total monthly expenses incurred by Copano Operations less (i) a fixed allocation to reflect expenses incurred by Copano Operations for the benefit of certain entities controlled by Mr. Eckel and (ii) any costs to be retained by Copano Operations or charged directly to an entity for which Copano Operations performed services. Our management believes that this methodology is reasonable. For the years ended December 31, 2007, 2006 and 2005, we reimbursed Copano Operations $3,250,000, $3,329,000 and $2,987,000, respectively, for administrative and operating costs, including payroll and benefits expense for certain of our field and administrative personnel. These costs are included in operations and maintenance expenses and general and administrative expenses on our consolidated statements of operations. Certain of our subsidiaries are co-lessors of office space with Copano Operations. As of December 31, 2007 and 2006, amounts payable by us to Copano Operations were $81,000 and $32,000, respectively.

Our management estimates that these expenses on a stand-alone basis (that is, the cost that would have been incurred by us to conduct our current operations if we had obtained these services from an unaffiliated entity) would not be significantly different from the amounts we recorded in our consolidated financial statements for each of the three years in the period ended December 31, 2007.

Note 9 — Related Party Transactions — (continued)

Natural Gas and Related Transactions

The following table summarizes transactions between us and affiliated entities (in thousands):

	Year Ended December 31,		
	2007	2006	2005
Affiliates of Mr. Eckel:			
Natural gas sales(1)	$ 31	$ 97	$ —
Gathering and compression services(2)	30	32	31
Natural gas purchases(3)	2,251	1,808	1,495
Webb Duval:			
Natural gas sales(1)	—	706	355
Natural gas purchases(3)	955	1,695	3,359
Transportation costs(4)	357	358	475
Southern Dome:			
Natural gas liquid sales(5)	302	—	—
Condensate sales(6)	145	—	—
Bighorn:(7)			
Gathering costs(4)	166	—	—
Fort Union:(7)			
Gathering costs(4)	2,110		
Treating costs(3)	125	—	—
Other:(8)			
Natural gas sales(1)	212	—	—

(1) Revenues included in natural gas sales on our consolidated statements of operations.

(2) Revenues included in transportation, compression and processing fees on our consolidated statements of operations.

(3) Included in costs of natural gas and natural gas liquids on our consolidated statements of operations.

(4) Costs included in transportation on our consolidated statements of operations.

(5) Revenues included in natural gas liquid sales on our consolidated statements of operations.

(6) Revenues included in condensate and other on our consolidated statements of operations.

(7) For the period from October 1, 2007 through December 31, 2007.

(8) For the period from May 1, 2007 through December 31, 2007.

Additionally, affiliated companies of Mr. Eckel reimbursed us $0, $43,000 and $93,000 for the years ended December 31, 2007, 2006 and 2005, respectively, in gas lift costs, which are reflected as a reduction of operations and maintenance expense on our consolidated statements of operations. As of December 31, 2007 and 2006, amounts payable by us to affiliated companies of Mr. Eckel, other than Copano Operations, totaled $177,000 and $91,000, respectively.

Well connection fees paid to Webb Duval totaled $67,000 for the year ended December 31, 2005. During 2006, we, as operator of Webb Duval, replaced a compressor on the Webb Duval gathering system through (i) our acquisition of that compressor from Webb Duval for $681,000 and (ii) the sale of a more suitable replacement compressor by us to Webb Duval for $658,000. Given that both compressors had been recently acquired, these

Note 9 — Related Party Transactions — (continued)

prices reflected the original purchase prices paid to the equipment supplier. In connection with our acquisition of the compressor from Webb Duval, we reimbursed Webb Duval $220,000 for certain compressor installation costs previously incurred by Webb Duval. Additionally, as operator of Webb Duval, we charged Webb Duval administrative fees of $211,000, $192,000 and $192,000 for the years ended December 31, 2007, 2006 and 2005, respectively. As of December 31, 2007, our net payable to Webb Duval totaled $335,000 and, as of December 31, 2006, our net receivable from Webb Duval totaled $532,000.

We receive a management fee of $250,000 per year from Southern Dome, which, along with any other reimbursable costs, is the total compensation paid to us by Southern Dome. For the year ended December 31, 2007, Southern Dome paid us $250,000 in management fees and $448,000 in other reimbursable costs. For the year ended December 31, 2006, Southern Dome paid us $250,000 in management fees and $1,124,000 in other reimbursable costs. For the period from August 1, 2005 through December 31, 2005, Southern Dome paid us $104,000 in management fees and $189,000 in other reimbursable costs. As of December 31, 2007 and 2006, our net receivable from Southern Dome totaled $820,000 and $147,000, respectively.

We receive management fees and cost reimbursements from Bighorn, and cost reimbursements from Fort Union, which is the total compensation paid to us by Bighorn and Fort Union. For the period from October 1, 2007 through December 31, 2007, Bighorn paid us $115,000 in management fees and $49,000 in other reimbursable costs. For the period from October 1, 2007 through December 31, 2007, Fort Union paid us $22,000 in reimbursable costs. As of December 31, 2007, our receivables from Bighorn and Fort Union totaled $323,000 and $14,000, respectively. As of December 31, 2007, our payable to Fort Union totaled $759,000.

Our management believes these transactions were on terms no less favorable than those that could have been achieved with an unaffiliated entity.

Note 10 — Customer Information

The following tables summarize our significant customer information for the period indicated.

Percentage of Consolidated Revenue[(1)]

Customer	Segment	Year Ended December 31, 2007	2006	2005
Enterprise Products Operating, L.P.	Texas	20%	19%	—
ONEOK Energy Services, L.P.	Oklahoma	16%	21%	—
ONEOK Hydrocarbon, L.P.	Oklahoma	14%	13%	—
KMTP	Texas	10%	14%	26%
Dow Hydrocarbons and Resources Inc.	Texas	—	—	12%

Percentage of Consolidated Cost of Goods Sold[(1)]

Producers	Segment	Year Ended December 31, 2007	2006	2005
New Dominion LLC	Oklahoma	18%	19%	8%
Altex Resources, Inc.	Oklahoma	—%	5%	—
Noble Energy, Inc.	Texas	—%	—	7%

Note 10 — Customer Information — (Continued)

Percentage of Consolidated Accounts Receivable(1)

Customer	Segment	Year Ended December 31, 2007	2006	2005
ONEOK Energy Services, L.P.	Oklahoma	18%	25%	27%
ONEOK Hydrocarbon, L.P.	Oklahoma	13%	13%	—
Enterprise Products Operating, L.P.	Texas	10%	11%	—
KMTP	Texas	8%	12%	23%
CenterPoint Energy, Inc.	Texas	—	—	10%

(1) Percentages are not provided for periods for which the customer or producer is not considered significant.

Note 11 — Risk Management Activities

We are exposed to market risks, including changes in commodity prices and interest rates. We may use financial instruments such as puts, calls, swaps and other financial instruments to mitigate the effects of the identified risks. In general, we attempt to hedge risks related to the variability of future earnings and cash flows resulting from changes in applicable commodity prices or interest rates so that we can maintain cash flows sufficient to meet debt service, required capital expenditures, distribution objectives and similar requirements. Our risk management policy prohibits the use of derivative instruments for speculative purposes.

Commodity Risk Hedging Program

NGL and natural gas prices are volatile and are impacted by changes in fundamental supply and demand, as well as market uncertainty and a variety of additional factors that are beyond our control. Our profitability is affected by prevailing commodity prices primarily as a result of two components of our business: (i) processing or conditioning at our processing plants or third-party processing plants and (ii) purchasing and selling volumes of natural gas at index-related prices. In order to manage the risks associated with natural gas and NGL prices, we engage in risk management activities that take the form of commodity derivative instruments. These activities are governed by our risk management policy, as amended, which allows our management to purchase crude oil, NGLs and natural gas options and enter into swaps in order to reduce our exposure to a substantial adverse change in the prices of those commodities.

Our Risk Management Committee monitors and ensures compliance with the risk management policy and is comprised of senior level executives in the operations, finance and legal departments. The Audit Committee of our Board of Directors monitors the implementation of the policy and we have engaged an independent firm to provide additional oversight. The risk management policy requires derivative transactions to take place either on the New York Mercantile Exchange (NYMEX) through a clearing member firm or with over-the-counter counterparties with investment grade ratings from both Moody's Investors Service and Standard & Poor's Ratings Services with complete industry standard contractual documentation. Under this documentation, the payment obligations in connection with our swap transactions are secured by a first priority lien in the collateral securing our senior secured indebtedness that ranks equal in right of payment with liens granted in favor of our senior secured lenders. As long as this first priority lien is in effect, we will have no obligation to post cash, letters of credit or other additional collateral to secure these hedges at any time even if our counterparty's exposure to our credit increases over the term of the hedge as a result of higher commodity prices or because there has been a change in our creditworthiness.

Potential derivative transactions are analyzed to evaluate their effectiveness within our risk management strategy. These financial instruments are generally classified as cash flow hedges under SFAS No. 133 and are recorded on our consolidated balance sheets at fair value. For derivatives designated as cash flow hedges, we

Note 11 — Risk Management Activities — (Continued)

recognize the effective portion of changes in fair value as other comprehensive income, or OCI, and reclassify them to revenue within the consolidated statements of income as the underlying transactions impact earnings. For derivatives that are de-designated or were not originally designated as cash flows hedges and for the ineffective portion of cash flow hedges, we recognize changes in fair value as a component of revenue in our consolidated statements of income as they occur. For 2007, $9.9 million was reclassified to earnings as a result of discontinuing various cash flow hedges upon determining that the forecasted transactions were probable of not occurring.

The following table summarizes our current risk management portfolio. We assess, both at the inception of the hedge and on an ongoing basis, whether the derivatives are effective in hedging the variability of forecasted cash flows of underlying hedged items. If it is determined that a derivative is not effective as a hedge or that it has ceased to be an effective hedge due to the loss of correlation between the hedging instrument and the underlying hedged item, we discontinue hedge accounting and subsequent changes in the derivative fair value are immediately recognized as a gain or loss (increase or decrease in revenue) in our consolidated statements of income.

		Term		Fair Value December 31,		Ineffectiveness Year Ended December 31,			Realized Gain (Loss) Year Ended December 31,			Estimate of OCI to be Reclassed to Earnings in the Next 12 Months
		From	To	2007	2006	2007	2006	2005	2007	2006	2005	
				(In thousands)								
West Texas Intermediate crude oil[1]	Put	September 2005	December 2007	$ —	$ 178	$ —	$ (40)	$(35)	$(2,088)	$(1,376)	$(12)	$ —
Natural Gas[2]	Put	January 2006	December 2009	3,285	14,118	(18)	8	—	4,671	7,553	—	308
Natural Gas Liquids[2]	Put	January 2006	December 2008	2	3,714	6	(125)	—	(9,173)	(4,919)	—	10,523
Natural Gas Liquids[2]	Swap	January 2006	December 2008	(16,339)	(5,187)	(24)	(195)	—	(6,064)	448	—	26,811
Natural Gas Call Spreads[3]	Put/Call	January 2007	December 2011	8,676	7,589	—	—	—	2,434	—	—	703
West Texas Intermediate crude oil[1]	Put	January 2007	December 2011	625	4,603	53	—	—	(123)	—	—	997
Natural Gas Liquids[2]	Put	January 2007	December 2011	262	7,165	(17)	(1)	—	(1,321)	—	—	2,682
West Texas Intermediate crude oil[1]	Put	January 2008	December 2011	505	—	(6)	—	—	—	—	—	768
Natural Gas Liquids[2]	Put	January 2008	December 2011	528	—	(94)	—	—	(909)	—	—	3,636
Natural Gas Liquids[2]	Swap	January 2007	December 2011	(45,741)	—	(117)	—	—	(3,682)	—	—	26,811

(1) The derivatives are intended to hedge the risk of extreme adverse fluctuations of NGL prices with offsetting increases in the value of the crude oil puts based on the correlation between NGL prices and crude oil prices.

(2) The derivatives are intended to hedge the risk of extreme adverse fluctuations in the prices of the commodities hedged.

(3) The call spread is intended to hedge a portion of our net operational short position in natural gas that results when we operate in a processing mode at our Houston Central plant against adverse price fluctuations in the underlying price indices. The call spread reduces risk to the profitability and cash flow of the Houston Central plant.

In January 2008, we purchased puts for ethane, propane, iso-butane, normal butane and West Texas Intermediate crude oil at strike price reflecting current market conditions and divested previously acquired put options on these products at lower strike prices. These transactions were conducted through two investment grade counterparties in accordance with our risk management policy and were designated as cash flow hedges to mitigate the impact of increases in NGL prices. Our net costs for these transactions were approximately $15.6 million.

Note 11 — Risk Management Activities — (Continued)

Prior to our ScissorTail Acquisition, ScissorTail entered into certain derivative transactions on behalf of three suppliers from whom ScissorTail purchased a significant volume of natural gas. The arrangement with the suppliers provided that any gains or losses that resulted from the derivative transactions passed through to the suppliers. ScissorTail's credit exposure was guaranteed by the physical production from the three suppliers. The potential credit risk for each of the suppliers was evaluated on a regular basis and the volume available to hedge was modified to match a percentage of the supplier's actual volumes sold to ScissorTail. ScissorTail received a fee of $1,000 per month related to these transactions. ScissorTail did not and we have not recorded any other revenue or expenses associated with these derivative transactions. In October 2005, all of the positions under these derivative transactions expired.

Interest Rate Risk Hedging Program

Our interest rate exposure results from variable rate borrowings under our debt agreements. We manage a portion of our interest rate exposure by utilizing interest rate swaps, which allow us to convert a portion of variable rate debt into fixed rate debt.

In October 2005, we entered into two interest rate swap agreements with a notional amount of $25 million each in which we exchanged the payment of variable rate interest on a portion of the principal outstanding under the Credit Facility for fixed rate interest. Under each swap agreement, we pay the counterparties the fixed interest rate of approximately 4.7% monthly and receive back from the counterparties a variable interest rate based on one-month LIBOR rates. The interest rate swaps cover the period from October 2005 through July 2010 and the settlement amounts will be recognized to earnings as either an increase or a decrease in interest expense.

At inception, we designated these two interest rate swaps as cash flow hedges under SFAS No. 133. Effective in December 2006, we de-designated a portion of one of the interest rate swaps when we reduced the outstanding borrowings on our Credit Facility to $30 million. As a result, we hedged transactions representing the notional amount of $25 million on one interest rate swap and hedged transactions representing $5 million of the notional amount on the second interest rate swap. We adjusted our balance in OCI for the amount of the de-designated interest rate swap to reflect the portion of the gain necessary to offset the cumulative change in expected future cash flows on the hedged transaction, as required under paragraph 30(B)(2) of SFAS No. 133. In December 2006, we recognized a gain from other comprehensive income of $119,000 upon de-designation of the interest rate swap. We also recognized a gain of $50,000 for the portion of the gain between the de-designation date and December 31, 2006 that could not be recorded to OCI under paragraph 30 of SFAS No. 133. In January 2007, we amended and restated our Credit Facility, including extending its maturity date and, as a result, the terms of our outstanding interest rate swaps no longer exactly match the term of the Credit Facility. Consequently, we no longer use the "shortcut" method under SFAS No. 133 in accounting for our interest rate swaps. In March 2007, we borrowed $20 million under the Credit Facility, resulting in a principal amount equal to the notional amount of the interest rate swaps so that the total notional amount of both $25 million interest rate swaps effective October 2005 now qualify for hedge accounting.

In September 2007, we entered into a new interest rate swap agreement with a notional amount of $40 million under which we exchanged the payment of variable rate interest on a portion of the principal outstanding under the Credit Facility for fixed rate interest. Under this agreement, we pay the counterparty the fixed interest rate of approximately 4.77% monthly and receive back from the counterparty a variable interest rate based on three-month LIBOR rates. The interest rate swap covers the period from October 2007 through October 2011 and the settlement amounts will be recognized as either an increase or decrease in interest expense.

In October 2007, we entered into two additional interest rate swap agreements with an aggregate notional amount of $70 million under which we exchanged the payment of variable rate interest on a portion of the principal outstanding under the Credit Facility for fixed rate interest. Under these agreements, we pay the counterparty the fixed interest rate of approximately 4.7% monthly and receive back from the counterparty a variable interest rate

Note 11 — Risk Management Activities — (Continued)

based on three-month LIBOR rates. The interest rate swap covers the period from October 2007 through October 2012 and the settlement amounts will be recognized as either an increase or decrease in interest expense.

We estimate that $0.9 million of the amount reported in other comprehensive loss as of December 31, 2007 will be reclassified against earnings in the next 12 months.

Effective Date	Expiration Date	Notional Amount	Fixed Rate	Received (Paid) During the Year Ended December 31, 2007	2006	2005	Fair Value of Liability at December 31, 2007
October 24, 2005	July 31, 2010	$25,000,000	4.7150%	$133,000	$83,000	$(26,000)	$ 575,000
October 24, 2005	July 31, 2010	$25,000,000	4.7075%	$135,000	85,000	(28,000)	570,000
September 17, 2007	October 9, 2011	$40,000,000	4.7700%	$ 44,000	—	—	1,129,000
October 19, 2007	October 18, 2012	$45,000,000	4.6900%	$ 46,000	—	—	1,167,000
October 19, 2007	October 18, 2012	$25,000,000	4.6800%	$ 23,000	—	—	643,000

In January 2008, we entered into two new interest rate swap agreements with a notional amount of $25 million each under which we exchanged the payment of variable rate interest on a portion of the principal outstanding under the Credit Facility for fixed rate interest. Under each swap agreement, we pay the counterparty the fixed interest rate of approximately 3.23% monthly and receive back from the counterparty a variable interest rate based on three-month LIBOR rates. The interest rate swap covers the period from February 2008 through October 2012 and the settlement amounts will be recognized as either an increase or decrease in interest expense.

Note 12 — Fair Value of Financial Instruments

Amounts reflected in our consolidated balance sheets as of December 31, 2007 and 2006 for cash and cash equivalents is believed to approximate fair value because of its short nature and maturity. As of December 31, 2007 and 2006, the debt outstanding under the Credit Facility bore interest at a floating rate. As such, carrying amounts of Credit Facility debt approximate fair values. Estimates of the fair value of our Senior Notes are based on their current market information as of December 31, 2007.

	December 31, 2007 Carrying Value	2007 Estimated Fair Value	2006 Carrying Value	2006 Estimated Fair Value
	(In thousands)			
Cash and cash equivalents	$ 72,665	$ 72,665	$ 39,484	$ 39,484
Credit Facility	280,000	280,000	30,000	30,000
Senior Notes	350,773	352,625	225,000	232,875

Note 13 — Commitments and Contingencies

Commitments

For the years ended December 31, 2007, 2006 and 2005, rental expense for office space, leased vehicles and leased compressors and related field equipment used in our operations totaled $3,913,000, $3,447,000 and $1,642,000, respectively. As of December 31, 2007, commitments under our lease obligations for the next five years are payable as follows: *2008* — $3,322,000; *2009* — $1,701,000; *2010* — $1,205,000; *2011* — $740,000; and *2012* — $292,000.

We have both fixed and variable quantity contractual commitments arising in the ordinary course of our natural gas marketing activities. As of December 31, 2007, we had fixed contractual commitments to purchase 1,296,500 million British thermal units ("MMBtu") of natural gas in January 2008. As of December 31, 2007, we had fixed contractual commitments to sell 2,654,530 MMBtu of natural gas in January 2008. All of these contracts

Note 13 — Commitments and Contingencies (Continued)

are based on index-related market pricing. Using index-related market prices as of December 31, 2007, total commitments to purchase natural gas related to such agreements equaled $8,874,000 and the total commitment to sell natural gas under such agreements equaled $17,870,000. Our commitments to purchase variable quantities of natural gas at index-based prices range from contract periods extending from one month to the life of the dedicated production. During December 2007, natural gas volumes purchased under such contracts equaled 9,410,259 MMBtu. Our commitments to sell variable quantities of natural gas at index-based prices range from contract periods extending from one month to 2012. During December 2007, natural gas volumes sold under such contracts equaled 4,237,562 MMBtu.

In connection with the Cantera Acquisition, we assumed a "Contingent Consideration Note" to CMS Gas Transmission Company ("CMS"), dated as of July 2, 2003, that provides for annual payments to CMS through 2009 contingent upon Bighorn and Fort Union achieving certain earnings thresholds. If the earnings threshold is met for a given year, the payment for that year (in an amount equal to the lesser of the original contingent note payment indicated in the table below or a specified percentage of earnings) is due in March of the following year. The Contingent Consideration Note is subordinated to our senior indebtedness and payments will not exceed $50,000,000 in the aggregate. If the earnings threshold is not met for a given year, the liability for that year rolls forward one year and adds to the maximum contingent payment due the following year and then expires if not paid by the end of such following year. The earnings thresholds were not met for the years 2004 through 2007; therefore, there were no payments due in 2005, 2006 and 2007 and there will be no payment due in 2008. Because the earnings thresholds were not met for the years 2004 through 2007, the 2004, 2005 and 2006 contingent payments of $7,500,000, $9,167,000 and $10,833,000, respectively, expired and the 2007 contingent payment of $10,833,000 has rolled over to 2008.

Pursuant to the terms of the Contingent Consideration Note, at December 31, 2007, annual contingent payments are limited to the following (in thousands):

Year Ended December 31,	Payment due March	Status	Original Contingent Note Payments	Contingent Note Maximum Payments
2004	2005	Expired	$ 7,500	$ —
2005	2006	Expired	9,167	—
2006	2007	Expired	10,833	—
2007	2008	Rolled to 2008	10,833	—
2008	2009		11,667	22,500
			$50,000	$22,500

Also, in connection with the Cantera Acquisition, we assumed two firm transportation agreements with a third-party owner of a natural gas pipeline, under which we are obligated to pay for transportation capacity whether or not we use such capacity. Under these two agreements, we are obligated to pay approximately $10,477,000 in 2008, $10,471,000 in 2009, $9,961,000 in 2010, $9,927,000 in 2011, $9,840,000 in 2012 and $33,778,000 thereafter. Beginning in April 2007, the majority of our obligations, and beginning in June 2008, all our obligations under these two firm transportation agreements are offset by capacity release agreements between us and third parties, under which they have agreed to use all of our firm transportation capacity through December 31, 2019. Both agreements expire on December 31, 2019.

Additionally, we assumed two firm gathering agreements with Fort Union, under which we are obligated to pay for gathering capacity on the Fort Union system whether or not we use such capacity. Under these agreements, we are obligated to pay approximately $10,153,000 for 2008, $10,760,000 for 2009, $4,582,000 for 2010, $5,859,000 for 2011, $7,154,000 for 2012 and $7,665,000 for each of the years thereafter. We have sub-

Note 13 — Commitments and Contingencies (Continued)

contracted a portion of this commitment to a third party for the duration of the contract. These agreements expire in November 2009 and November 30, 2017.

Guarantees

FIN 45, *"Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others,"* sets forth disclosure requirements for guarantees by a parent company on behalf of its subsidiaries. We may, from time to time, issue parent guarantees of commitments resulting from the ongoing activities of subsidiary entities. Additionally, a subsidiary entity may from time to time issue a guarantee of commitments resulting from the ongoing activities of another subsidiary entity. The guarantees generally arise in connection with a subsidiary commodity purchase obligation or subsidiary lease commitments. The nature of such guarantees is to guarantee the performance of the subsidiary entities in meeting their respective underlying obligations. Except for operating lease commitments, all such underlying obligations are recorded on the books of the subsidiary entities and are included in our consolidated financial statements as obligations of the combined entities. Accordingly, such obligations are not recorded again on the books of the parent. The parent would only be called upon to perform under the guarantee in the event of a payment default by the applicable subsidiary entity. In satisfying such obligations, the parent would first look to the assets of the defaulting subsidiary entity. As of December 31, 2007, the amount of parental guaranteed obligations totaled approximately $3,300,000, all of which were related to our commodity purchases.

Regulatory Compliance

In the ordinary course of business, we are subject to various laws and regulations. In the opinion of our management, compliance with existing laws and regulations will not materially affect our financial position.

Litigation

Although we may, from time to time, be involved in litigation and claims arising out of our operations in the normal course of business, we are not currently a party to any legal proceedings, except for proceedings described below, which we have determined not to be material to us because we are fully indemnified. In addition, we are not aware of any material legal or governmental proceedings against us, or contemplated to be brought against us, under the various environmental protection statutes to which we are subject, that would have a significant adverse effect on our financial position or results of operations.

As a result of our Cantera Acquisition in October 2007, we became a party to a number of legal proceedings alleging (i) false reporting of natural gas prices by CMS Field Services, Inc. ("CMSFS") (now Cantera Natural Gas, LLC) and numerous other parties and (ii) other related claims. The claims made in these proceedings are based on events that occurred prior to the acquisition of CMSFS by Cantera Resources, Inc. in June 2003 (the "CMS Acquisition"). Pursuant to the acquisition agreement executed in connection with the CMS Acquisition, CMS has assumed responsibility for the defense of these claims and we are fully indemnified by CMS against any losses that we may suffer as a result of these claims.

Note 14 — Supplemental Disclosures to the Statements of Cash Flows

	Year Ended December 31,		
	2007	2006	2005
Cash payments for interest, net of $932,000, $693,000 and $0 capitalized in 2007, 2006 and 2005, respectively	$24,471	$26,884	$9,666
Cash payments for federal and state income taxes	$ —	$ —	$ 15

Note 14 — Supplemental Disclosures to the Statements of Cash Flows (Continued)

We incurred an increase in liabilities for acquisitions and construction in progress that had not been paid as of December 31, 2007 and 2006 of $1,454,000 and $2,418,000, respectively. Such amounts are not included in the change in accounts payable and accrued liabilities or with acquisitions, additions to property, plant and equipment and intangible assets on the consolidated statements of cash flows.

Note 15 — Segment Information

We manage our business and analyze and report our results of operations on a segment basis. Our operations are divided into the following three segments for both internal and external reporting and analysis:

- Oklahoma, which includes natural gas midstream services in central and eastern Oklahoma, including natural gas gathering and related compression and dehydration services and natural gas processing and a crude oil pipeline. Our Oklahoma segment includes assets acquired in the Cimmarron Acquisition and our equity investment in Southern Dome.
- Texas, which performs natural gas gathering and transmission and related operations and natural gas processing, treating, conditioning and related NGL transportation operations in Texas and Louisiana. Our Texas segment includes assets acquired in the Cimmarron Acquisition and Cantera Acquisition and our equity investment in Webb Duval.
- Rocky Mountains, which performs natural gas gathering and related operations in Wyoming. Our Rocky Mountains segment consists of assets we acquired through the Cantera Acquisition, including our equity investments in Bighorn and Fort Union.

The amounts indicated below as "Corporate and Other" relate to our risk management activities, intersegment eliminations and other activities we perform or assets we hold that have not been allocated to any of our reporting segments.

We evaluate segment performance based on segment gross margin before depreciation and amortization. All of our revenue is derived from, and all of our assets and operations are located in, Oklahoma, Texas, Wyoming and Louisiana in the United States. Transactions between reportable segments are conducted on terms similar to those conducted on an arm's length basis. Operating and maintenance expenses and general and administrative expenses incurred at Corporate and Other are allocated to Oklahoma, Texas and Rocky Mountains based on actual expenses incurred by each segment or an allocation based on activity, as appropriate.

Note 15 — Segment Information (Continued)

Summarized financial information concerning our reportable segments is shown in the following table (in thousands). Prior year information has been restated to conform to the current year presentation of our segment information.

	Oklahoma	Texas	Rocky Mountains	Total Segments	Corporate and Other	Consolidated
Year Ended December 31, 2007:						
Sales to external customers	$589,371	$574,353	$ 9,181	$1,172,905	$(31,245)	$1,141,660
Intersegment sales	(400)	400	—	—	—	—
Interest and other financing costs	—	—	103	103	29,248	29,351
Depreciation and amortization	25,724	12,749	670	39,143	824	39,967
Equity in (earnings) loss from unconsolidated affiliates	(1,400)	(1,576)	126	(2,850)	—	(2,850)
Net income (loss)	63,758	73,976	(138)	137,596	(74,421)	63,175
Segment assets	682,850	397,192	686,851	1,766,893	2,190	1,769,083
Year Ended December 31, 2006:						
Sales to external customers	$411,196	$447,723	$ —	$ 858,919	$ 1,353	$ 860,272
Interest and other financing costs	—	2	—	2	32,902	32,904
Depreciation and amortization	23,054	8,452	—	31,506	487	31,993
Equity in earnings from unconsolidated affiliates	(91)	(1,206)	—	(1,297)	—	(1,297)
Net income (loss)	50,749	56,098	—	106,847	(41,733)	65,114
Segment assets	584,956	248,273	—	833,229	5,829	839,058
Year Ended December 31, 2005:						
Sales to external customers	$200,426	$546,957	$ —	$ 747,383	$ 360	$ 747,743
Interest and other financing costs	—	3,924	—	3,924	16,537	20,461
Depreciation and amortization	9,181	7,731	—	16,912	140	17,052
Equity in loss (earnings) from unconsolidated affiliates	7	(934)	—	(927)	—	(927)
Net income (loss)	23,610	28,716	—	52,326	(21,974)	30,352

Note 16 — Quarterly Financial Data (Unaudited)

	Year 2007				
	Quarter Ended				
	March 31	June 30(1)	September 30(1)	December 31(1)	Year
	(In thousands, except per unit information)				
Revenue	$210,988	$281,720	$293,076	$355,876	$1,141,660
Operating income	14,179	18,957	26,006	32,244	91,386
Net income	8,702	13,308	19,667	21,498	63,175
Basic net income per common unit	0.21	0.31	0.46	0.46	1.48
Diluted net income per common unit	0.20	0.31	0.44	0.39	1.36
Basic net income per subordinated unit	0.21	—	—	—	0.21
Diluted net income per subordinated unit	0.21	—	—	—	0.21

	Year 2006				
	Quarter Ended				
	March 31	June 30(1)	September 30(1)	December 31(1)	Year
	(In thousands, except per unit information)				
Revenue	$213,960	$209,627	$231,311	$205,374	$860,272
Operating income	15,347	26,148	31,090	23,727	96,312
Net income	7,413	18,887	22,283	16,531	65,114
Basic net income per common unit	0.20	0.52	0.61	0.44	1.77
Diluted net income per common unit	0.20	0.51	0.60	0.43	1.75
Basic net income per subordinated unit	0.20	0.52	0.61	0.44	1.77
Diluted net income per subordinated unit	0.20	0.52	0.61	0.43	1.76

(1) Our historical results of operations for the quarters ended June 30, 2007, September 30, 2007 and December 31, 2007 may not be comparable to the first quarter of 2007 or quarters in 2006 as a result of the Cimmarron Acquisition in May 2007 and the Cantera Acquisition in October 2007.

INDEPENDENT AUDITOR'S REPORT

To the Operating Member of Bighorn Gas Gathering, L.L.C.:

We have audited the accompanying balance sheet of Bighorn Gas Gathering, L.L.C. (the "Company") as of December 31, 2007 and the related statements of operations, members' equity and cash flows for the period from October 1, 2007 through December 31, 2007. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with generally accepted auditing standards as established by the Auditing Standards Board (United States) and in accordance with the auditing standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, such financial statements present fairly, in all material respects, the financial position of the Company at December 31, 2007, and the results of its operations and its cash flows for the period from October 1, 2007 through December 31, 2007 in conformity with accounting principles generally accepted in the United States of America.

/s/ Deloitte & Touche LLP

Denver, Colorado
February 29, 2008

BIGHORN GAS GATHERING, L.L.C.

BALANCE SHEET

December 31, 2007

ASSETS

Current assets:	
Cash and cash equivalents	$ 3,660,296
Accounts receivable	3,203,418
Prepaid expenses	116,957
Total current assets	6,980,671
Property and equipment, net	97,327,215
Other assets	243,138
Total assets	$104,551,024

LIABILITIES AND MEMBERS' EQUITY

Current liabilities:	
Accounts payable:	
Trade	$ 1,431,940
Related parties	323,054
Accrued liabilities	167,905
Total current liabilities	1,922,899
Commitments and contingencies (Note 6)	
Members' equity	102,628,125
Total liabilities and members' equity	$104,551,024

See accompanying notes to financial statements.

BIGHORN GAS GATHERING, L.L.C.

STATEMENT OF OPERATIONS

Period From October 1, 2007 through December 31, 2007

Gathering fee revenue	$7,809,074
Expenses:	
Operating expenses	2,605,066
General and administrative	81,836
Depreciation	994,432
Total expenses	3,681,334
Operating income	4,127,740
Other income:	
Interest income	24,367
Other expense	(309)
Total other income	24,058
Net income	$4,151,798

See accompanying notes to financial statements.

BIGHORN GAS GATHERING, L.L.C.

STATEMENT OF CASH FLOWS

Period From October 1, 2007 through December 31, 2007

Cash flow from operating activities:	
Net income	$ 4,151,798
Adjustments to reconcile net income to net cash provided by operating activities:	
Depreciation	994,432
Changes in operating assets and liabilities:	
Accounts receivable	269,988
Prepaid expenses and other	53,232
Accounts payable	(524,106)
Accrued liabilities	81,150
Net cash provided by operating activities	5,026,494
Cash flow from investing activities:	
Capital expenditures	(4,117,405)
Net cash used in investing activities	(4,117,405)
Cash flow from financing activities:	
Priority distributions to members	(583,932)
Distributions to common members	(4,000,000)
Equity contributions from common members	2,896,501
Net cash used in financing activities	(1,687,431)
Net decrease in cash and cash equivalents	(778,342)
Cash and cash equivalents, beginning of period	4,438,638
Cash and cash equivalents, end of year	$ 3,660,296

See accompanying notes to financial statements.

BIGHORN GAS GATHERING, L.L.C.

STATEMENT OF MEMBERS' EQUITY

Period From October 1, 2007 through December 31, 2007

	Common Member Interests			
	Copano Pipelines/Rocky Mountains, LLC (formerly Cantera Gas Holdings, L.L.C.)	Crestone Energy Ventures, L.L.C.	Crestone Gathering Services, L.L.C.	Total
Balance at October 1, 2007	$51,083,517	$39,063,861	$10,016,380	$100,163,758
Contributions	2,814,057	65,618	16,826	2,896,501
Allocation of 2007 contributions	(1,336,841)	1,064,016	272,825	—
Distributions	(2,623,932)	(1,560,000)	(400,000)	(4,583,932)
Net income	2,403,543	1,391,469	356,786	4,151,798
Balance at December 31, 2007	$52,340,344	$40,024,964	$10,262,817	$102,628,125

See accompanying notes to financial statements.

NOTES TO FINANCIAL STATEMENTS

Note 1 — Organization and Business

Bighorn Gas Gathering, L.L.C. (the "Company") is a Delaware limited liability company. The Company was formed in 1999 to construct and operate natural gas gathering lines and related facilities in the Powder River Basin of Northern Wyoming. As of December 31, 2007, the members' common equity interests were owned by the following:

Copano Pipelines/Rocky Mountains, LLC ("Copano") (formerly Cantera Gas Holdings, L.L.C.), a subsidiary of Copano Natural Gas/Rocky Mountains, LLC (formerly Cantera Natural Gas, L.L.C.)	51%
Crestone Energy Ventures, L.L.C. ("Crestone Energy")	39
Crestone Gathering Services, L.L.C. ("Crestone Gathering")	10
	100%

Contributions from the Company's common members may be required from time to time and are generally required from each member in proportion to their respective ownership percentage. In addition, members may propose capital additions to the Company's gathering and transportation system. In the event that all members do not consent, consenting members may make capital contributions to the Company, which would be used to fund the prospective capital addition. Such contributions are immediately reallocated to the equity accounts of each member in proportion to their respective ownership interests. Consenting members are entitled to a priority distribution of up to 140% of the amount of capital contributed by such consenting members, as discussed below. Members' liabilities are limited to the amount of capital contributed.

For the period from October 1, 2007 through December 31, 2007, common members contributed $2,896,501, including $2,728,247 from Copano related to nonconsent capital projects. The $2,728,247 of additional capital contributed by Copano was reallocated to common members, resulting in a $1,336,841 decrease in Copano's common member interest and a corresponding increase in the remaining members' interests.

Priority distributions related to net recovery from nonconsent capital projects are made in priority to common distributions. Once 140% of the capital contributed by consenting members has been distributed, net revenue from nonconsent projects is distributable as common distributions. Common member distributions are made for cash flows from the Company's operations, as defined in the member agreement, in proportion to the common members' respective ownership interests. For the period from October 1, 2007 through December 31, 2007, distributions to common members totaled $4,583,932, including priority distributions to Copano of $583,932.

As noted above, net revenue from nonconsent capital projects is attributable entirely to consenting members up to 140% of the contributed capital. Remaining income is allocated to common members in proportion to their respective ownership interests.

Note 2 — Summary of Significant Accounting Policies

Use of Estimates

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

Gas Gathering Operations

The Company's revenue is derived from fees collected for gathering natural gas. Revenue is recognized once the Company can conclude it has evidence of an arrangement, the fees are fixed or determinable, collectibility is

Note 2 — Summary of Significant Accounting Policies (Continued)

probable and delivery has occurred. The Company typically enters into long-term contracts that provide for per unit gathering fees. Fees are determined on a monthly basis based upon actual volumes and are recognized when the gas reaches the point of delivery. The Company assesses collectibility at the inception of an arrangement based upon credit ratings and prior collections history. In general, the Company conducts business with customers with whom the Company has a long collection history. As a result, the Company has not experienced significant credit losses nor has its revenue recognition been impacted due to assessments of collectibility. Costs are expensed as incurred.

Cash and Cash Equivalents

The Company considers all highly liquid cash investments with original maturities of three months or less when purchased to be cash equivalents.

Imbalances

Imbalances result when the Company's customers either over or under-deliver natural gas to the Company's system. In general, over or under-delivery into the Company's system is offset by the Company's equivalent over or under-delivery at the delivery points into the Fort Union gathering system, an affiliate of Copano, which are then cashed out. Accordingly, at December 31, 2007, the Company had no gas imbalances.

Property and Equipment

Property and equipment are recorded at cost. Maintenance and repairs are charged to expense as incurred. Expenditures that extend the useful lives of assets are capitalized. When assets are retired or otherwise disposed of, the costs of the assets and the related accumulated depreciation are removed from the accounts. Any gain or loss on retirements or dispositions is reflected in other income in the year in which the asset is disposed. Depreciation is provided on a straight-line basis over the estimated useful life for each asset. Property and equipment consists of the following at December 31, 2007:

	Useful Lives	
Vehicles	3 years	$ 922,866
Computer and communication equipment	5 years	511,341
Pipeline materials	N/A	26,243
Gathering lines and related equipment	30 years	120,550,468
		122,010,918
Less accumulated depreciation		(24,683,703)
Property and equipment, net		$ 97,327,215

Asset Impairment

The Company evaluates its long-lived assets for impairment whenever events or circumstances indicate the carrying value may not be recoverable. An impairment loss is recorded when the carrying amount of the asset is not recoverable from future estimated undiscounted cash flows and exceeds the fair value. During the period from October 1, 2007 through December 31, 2007, no impairment of the Company's long-lived assets was recorded.

Fair Value of Financial Instruments

The Company's financial instruments consist of cash, accounts receivable, accounts payable and other current liabilities. The carrying amounts of financial instruments approximate fair value due to their short maturities.

Note 2 — Summary of Significant Accounting Policies (Continued)

Concentration of Credit Risk

Substantially all of the Company's accounts receivable at December 31, 2007 results from gas-gathering fees earned from other companies in the oil and gas industry. This concentration of customers may impact the Company's overall credit risk, either positively or negatively, in that these entities may be similarly affected by industry-wide changes in economic or other conditions. Such receivables are generally not collateralized. However, the Company performs credit evaluations on all its customers to minimize exposure to credit risk. During the period from October 1, 2007 through December 31, 2007, credit losses were not significant.

As of December 31, 2007, trade accounts receivable includes receivables from four customers representing 44.2%, 23.5%, 15.9% and 13.1% of total accounts receivable.

For the period from October 1, 2007 through December 31, 2007, revenue includes sales to two customers representing 68.4% and 21.6% of total revenue.

Income Taxes

Due to the Company's limited liability status, the income tax consequences of the Company pass through to the individual members. Accordingly, no provision has been made for federal or state income taxes.

In June 2006, the Financial Accounting Standards Board ("FASB") issued FASB Interpretation No. ("FIN") 48, "*Accounting for Uncertainty in Income Taxes — an Interpretation of FASB Statement No. 109.",*" FIN 48 clarifies the accounting for uncertainty in income taxes recognized in a company's financial statements in accordance with Statement of Financial Accounting Standards ("SFAS") No. 109 by prescribing thresholds and attributes for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. The provisions of FIN 48 became effective as of the beginning of the 2007 fiscal year and the adoption of FIN 48 did not have a material impact on the Company's results of operations, cash flows or financial position.

Note 3 — New Accounting Pronouncements

Fair Value Measurements

In September 2006, the FASB issued SFAS No. 157, *"Fair Value Measurements."* SFAS No. 157 establishes a framework for measuring fair values under generally accepted accounting principles and applies to other pronouncements that either permit or require fair value measurement, including SFAS No. 133, "*Accounting for Derivative Instruments and Hedging Activities,*" as amended and interpreted. The standard is effective for reporting periods beginning after November 15, 2007. The Company adopted this statement beginning January 1, 2008, and the adoption did not have a material impact on its cash flows, results of operations or financial position.

Fair Value Option for Financial Assets and Financial Liabilities

In February 2007, the FASB issued SFAS No. 159, *"The Fair Value Option for Financial Assets and Financial Liabilities,"* which permits entities to choose to measure many financial instruments and certain other items at fair value. SFAS No. 159 is effective for the Company as of January 1, 2008 and will have no impact on amounts presented for periods prior to the effective date. The Company adopted this statement beginning January 1, 2008 and the adoption did not have a material impact on its cash flows, results of operations or financial position. The Company has chosen not to measure items subject to SFAS No. 159 at fair value.

Note 3 — New Accounting Pronouncements (Continued)

Business Combinations

In December 2007, the FASB issued SFAS No. 141 (Revised), "*Business Combinations*" ("SFAS No. 141(R)"). The Company has not completed its assessment of the impact, if any, of its adoption of SFAS No. 141(R). SFAS No. 141(R) is effective for fiscal years beginning after November 15, 2008.

Note 4 — Operating Leases

The Company leases certain equipment for use on its gathering system under month-to-month and long term operating leases. The following is a schedule of future minimum rental payments required under operating leases as of December 31, 2007. At the end of the current lease terms, substantially all leases convert to month-to-month leases.

Year Ending December 31,	
2008	$ 995,542
2009	436,944
2010	38,962
	$1,471,448

For the period from October 1, 2007 through December 31, 2007, rent expense totaled $843,318.

Note 5 — Related-Party Transactions

During the period from October 1, 2007 through December 31, 2007, gathering services provided to Copano accounted for approximately 2.1% of the Company's total revenue. As of December 31, 2007, accounts receivable include $0 for these services.

The Company pays Copano management fees related to the operation and administration of the gathering system. For the period from October 1, 2007 through December 31, 2007, the Company reflected in operating expenses and general and administrative management fees totaling $114,612 and reimbursable costs totaling $49,000.

As of December 31, 2007, the Company had accounts payable to Copano of $323,054. Of the amount due Copano, $323,039 is related to services and reimbursements of expenses. The remainder of the December 31, 2007 balance of $15 includes amounts due to members for imbalance cash-outs.

Note 6 — Commitments and Contingencies

From time to time, the Company is involved in legal administrative proceedings or claims, which arise in the ordinary course of business. While such matters always contain an element of uncertainty, management believes that matters of which they are aware will not individually or in the aggregate have a material adverse effect on the Company's financial position or results of operations.