Copano Energy

Copano Energy Reports Third Quarter 2011 Results

Operating Segment Gross Margin Increased 32% and Service Throughput Increased 23% Over 2010

HOUSTON, Nov. 3, 2011 /PRNewswire/ -- Copano Energy, L.L.C. (NASDAQ: CPNO) today announced its financial results for the three and nine months ended September 30, 2011.

"We are pleased with our third quarter results as our operating segment gross margin continues to benefit from growing volumes in the Eagle Ford Shale and the north Barnett Shale Combo areas and a strong NGL pricing environment," said R. Bruce Northcutt, Copano Energy's President and Chief Executive Officer.

"We are making significant progress on our Eagle Ford Shale strategy as we complete and integrate the bulk of our 2011 projects, several of which have begun accepting volumes on a limited basis.

"We continue to see strong producer activity in the Eagle Ford Shale and when these projects are placed into full-service, they will have an immediate and positive impact on our distributable cash flow and distribution coverage," Northcutt added.

Third Quarter Financial Results

Total distributable cash flow for the third quarter of 2011 increased 3% to $36.9 million from $35.7 million for the third quarter of 2010 and decreased 2% from $37.6 million in the second quarter of 2011. Third quarter 2011 total distributable cash flow represents 95% coverage of the third quarter distribution of $0.575 per unit, based on common units outstanding on the distribution record date.

Revenue for the third quarter of 2011 increased 49% to $353.7 million compared to $237.7 million for the third quarter of 2010 and increased 2% compared to $346.1 million in the second quarter of 2011. Operating segment gross margin increased 32% to $72.8 million compared to $55.3 million for the third quarter of 2010 and decreased 4% compared to $75.6 million in the second quarter of 2011. Total segment gross margin increased 12% to $64.8 million for the third quarter of 2011 compared to $57.9 million for the third quarter of 2010 and decreased 1% compared to $65.3 million for the second quarter of 2011.

Adjusted EBITDA for the third quarter of 2011 was $51.8 million compared to $51.0 million for the third quarter of 2010 and $54.4 million for the second quarter of 2011.

Net loss was $157.7 million for the third quarter of 2011 compared to net income of $7.3 million for the third quarter of 2010. Net loss for the third quarter of 2011 includes a $170 million non-cash impairment charge relating to the Company's assets in the Rocky Mountains primarily based on a downward shift in the Colorado Interstate Gas forward price curve and our expectations of a continued weak outlook for Rocky Mountains natural gas prices and drilling activity in Wyoming's Powder River Basin.

Net loss to common units after deducting $8.3 million of in-kind preferred unit distributions totaled $166.0 million, or $2.51 per unit on a diluted basis, for the third quarter of 2011 compared to net loss to common units of $0.2 million, or less than $0.01 per unit on a diluted basis, for the third quarter of 2010. Weighted average diluted units outstanding totaled 66.2 million for the third quarter of 2011 as compared to 65.7 million for the same period in 2010. Excluding the impact of the non-cash impairment charge, adjusted net income to common units totaled $4.0 million, or approximately $0.06 per unit on a diluted basis, for the third quarter of 2011.

Total distributable cash flow, total segment gross margin, adjusted EBITDA, segment gross margin and adjusted net income are non-GAAP financial measures, which are reconciled to their most directly comparable GAAP measures at the end of this press release. Commencing with the second quarter of 2011, Copano revised its method for calculating adjusted EBITDA and its presentation of total distributable cash flow. For a detailed discussion of these changes, please read *"Use of Non-GAAP Financial Measures"* beginning on page 7 of this news release.

Third Quarter Operating Results by Segment

Copano manages its business in three geographical operating segments: Texas, which provides midstream natural gas services in north and south Texas and also includes a processing plant in southwest Louisiana; Oklahoma, which provides midstream natural gas services in central and east Oklahoma; and the Rocky Mountains, which provides midstream natural gas services to producers in Wyoming's Powder River Basin and includes managing member interests in Bighorn Gas Gathering, L.L.C. (Bighorn) of 51% and in Fort Union Gas Gathering, L.L.C. (Fort Union) of 37.04%.

Texas

Segment gross margin for Texas increased 43% to $44.5 million for the third quarter of 2011 compared to $31.2 million for the third quarter of 2010 and decreased 3% from $46.1 million for the second quarter of 2011. The year-over-year increase resulted primarily from (i) a 9% increase in realized margins on service throughput compared to the third quarter of 2010 ($0.63 per MMBtu in 2011 compared to $0.58 per MMBtu in 2010) reflecting higher NGL prices and (ii) an increase in pipeline throughput associated with fee-based contracts in the Eagle Ford Shale and the north Barnett Shale Combo plays. During the third quarter of 2011, throughput volumes for the Eagle Ford Shale and the north Barnett Shale Combo plays increased 25% and 41%, respectively, from the second quarter of 2011. During the third quarter of 2011, weighted-average NGL prices on the Mont Belvieu index, based on Copano's product mix for the period, were $59.43 per barrel compared to $40.16 per barrel during the third quarter of 2010, an increase of 48%. During the third quarter of 2011, natural gas prices on the Houston Ship Channel index averaged $4.23 per MMBtu compared to $4 .33 per MMBtu during the third quarter of 2010, a decrease of 2%.

During the third quarter of 2011, the Texas segment provided gathering, transportation and processing services for an average of 765,744 MMBtu/d of natural gas compared to 590,116 MMBtu/d for the third quarter of 2010, an increase of 30%. The Texas segment gathered an average of 463,321 MMBtu/d of natural gas during the third quarter of 2011, an increase of 45% over last year's third quarter, primarily due to increased volumes from the Eagle Ford Shale and north Barnett Shale Combo plays. Processed volumes increased 33% to an average of 686,398 MMBtu/d of natural gas at Copano's plants and third-party plants. NGL production increased 57% to an average of 30,904 Bbls/d at Copano's plants and third-party plants, reflecting increased volumes behind Copano's Houston Central complex in south Texas and the Saint Jo plant in the north Barnett Shale Combo play in north Texas.

The decrease in segment gross margin from the second quarter of 2011 was a result of the curtailment of volumes at the Houston Central complex because a scheduled turnaround at the Point Comfort facility caused a downstream market constraint, the scheduled maintenance on the Company's purity propane line, and a decrease in volumes under a short-term and interruptible contract on the DK pipeline offset by increased Eagle Ford Shale volumes.

Oklahoma

Segment gross margin for Oklahoma increased 21% to $27.9 million for the third quarter of 2011 compared to $23.0 million for the third quarter of 2010 and decreased 3% from $28.7 million for the second quarter of 2011. The year-over-year increase resulted primarily from (i) a 13% increase in realized margins on service throughput compared to the third quarter of 2010 ($1.05 per MMBtu in 2011 compared to $0.93 per MMBtu in 2010), primarily reflecting higher NGL prices, (ii) the acquisition of the Harrah plant on April 1, 2011 and (iii) an increase in service throughput attributable to volume growth from the Woodford Shale. During the third quarter of 2011, weighted-average NGL prices on the Conway index, based on Copano's product mix for the period, were $49.21 per barrel compared to $36.53 per barrel during the third quarter of 2010, an increase of 35%. During the third quarter of 2011, natural gas prices on the CenterPoint East index averaged $4.05 per MMBtu compared to $4.14 per MMBtu during the third quarter of 2010, a decrease of 2%.

The Oklahoma segment gathered an average of 288,440 MMBtu/d of natural gas, processed an average of 158,070 MMBtu/d of natural gas and produced an average of 17,453 Bbls/d of NGLs at its own plants and third-party plants during the third quarter of 2011. Compared to the third quarter of 2010, this represents a 7% increase in service throughput, a 1% increase in plant inlet volumes and a 6% increase in NGL production. The increase in service throughput is primarily attributable to increased drilling and production of lean gas in the Woodford Shale area near Copano's Cyclone Mountain system, offset by normal production declines in rich gas areas.

The decrease in segment gross margin from the second quarter of 2011 was primarily related to a drop in natural gas and NGL prices.

Rocky Mountains

Segment gross margin for the Rocky Mountains segment totaled $0.4 million in the third quarter of 2011 compared to $1.1 million for the third quarter of 2010 and $0.8 million for the second quarter of 2011. The Rocky Mountains segment gross margin results do not include the financial results and volumes associated with Copano's interests in Bighorn and Fort Union, which are accounted for under the equity method of accounting and are shown in Copano's financial statements under "Equity in (earnings) loss from unconsolidated affiliates." Average pipeline throughput for Bighorn and Fort Union on a combined basis decreased 27% to 670,543 MMBtu/d in the third quarter of 2011 as compared to 913,730 MMBtu/d in the third quarter of 2010. The volume decline is primarily due to certain Fort Union shippers diverting gas volumes to TransCanada's Bison Pipeline upon its start up in January 2011. Fort Union volumes do not reflect 223,557 MMBtu/d in long-term contractually committed volumes that Fort Union did not gather but which were the basis of payments received by Fort Union for the three months ended September 30, 2011.

Corporate and Other

Corporate and other segment gross margin includes Copano's commodity risk management activities. These activities contributed a loss of $8.0 million for the third quarter of 2011 compared to income of $2.6 million for the third quarter of 2010 and a loss of $10.3 million for the second quarter of 2011. The loss for the third quarter of 2011 included $7.4 million of non-cash amortization expense relating to the option component of Copano's risk management portfolio and $2.9 million of net cash settlements paid for expired commodity derivative instruments offset by $2.3 million of unrealized gains on undesignated economic hedges. The third quarter 2010 gain included $11.1 million of net cash settlements received for expired commodity derivative instruments offset by $8.2 million of non-cash amortization expense relating to the option component of Copano's risk management portfolio and $0.3 million of unrealized mark-to-market losses on undesignated economic hedges.

Year to Date Financial Results

Revenue for the nine months ended September 30, 2011 increased 35% to $989.7 million compared to $734.4 million for the same period in 2010. Operating segment gross margin increased 34% to $217.6 million compared to $162.6 million for the nine months ended September 30, 2010. Total segment gross margin increased 15% to $190.5 million for the nine months ended September 30, 2011 compared to $165.9 million for the same period in 2010.

Adjusted EBITDA for the nine months ended September 30, 2011 was $153.6 million compared to $146.3 million for the same period in 2010.

Net loss was $163.6 million for the nine months ended September 30, 2011 compared to net loss of $15.1 million for the same period in 2010. Net loss for the first nine months of 2011 includes a loss on the refinancing of unsecured debt of $18.2 million and a $170.0 million non-cash impairment charge relating to our Rocky Mountains assets discussed above. Net loss for the first nine months of 2010 includes a $25 million non-cash impairment charge relating to the Company's investment in Bighorn.

Net loss to common units after deducting $24.2 million of in-kind preferred unit distributions beginning in July 2010 totaled $187.8 million, or $2.84 per unit on a diluted basis, for the nine months ended September 30, 2011 compared to net loss to common units of $22.6 million, or $0.36 per unit on a diluted basis, for the same period in 2010. Weighted average diluted units outstanding totaled 66.1 million for the nine months ended September 30, 2011 as compared to 63.2 million for the same period in 2010.

Cash Distributions

On October 12, 2011, Copano announced its third quarter 2011 cash distribution of $0.575 per unit, or $2.30 per unit on an annualized basis, for all of its outstanding common units. This distribution is unchanged from the second quarter of 2011 and will be paid on November 10, 2011 to common unitholders of record at the close of business on October 31, 2011.

Conference Call Information

Copano will hold a conference call to discuss its third quarter 2011 financial results on November 4, 2011 at 10:00 a.m. Eastern Time (9:00 a.m. Central Time). To participate in the call, dial (480) 629-9818 and ask for the Copano call 10 minutes prior to the start time, or access it live over the internet at www.copanoenergy.com on the "Investor Overview" page of the "Investor Relations" section of Copano's website.

A replay of the audio webcast will be available shortly after the call on Copano's website. A telephonic replay will be available through November 11, 2011 by calling (303) 590-3030 and using the pass code 4476344#.

Use of Non-GAAP Financial Measures

This news release and the accompanying schedules include the non-generally accepted accounting principles, or non-GAAP, financial measures of total distributable cash flow, total segment gross margin, adjusted EBITDA and segment gross margin. The accompanying schedules provide reconciliations of these non-GAAP financial measures to their most directly comparable financial measures calculated and presented in accordance with accounting principles generally accepted in the United States, or GAAP. Non-GAAP financial measures should not be considered as alternatives to GAAP measures such as net income (loss), operating income (loss), income (loss) from continuing operations, cash flows from operating activities or any other GAAP measure of liquidity or financial performance. Copano's non-GAAP financial measures may not be comparable to similarly titled measures of other companies, which may not calculate their measures in the same manner.

Copano's management team uses non-GAAP financial measures to evaluate its core profitability and to assess the financial performance of its assets. Subject to the limitations expressed above, Copano believes that investors and other market participants benefit from access to the same financial measures that its management uses in evaluating its performance.

Adjusted EBITDA. Commencing with the second quarter of 2011, Copano revised its calculation of adjusted EBITDA to more closely resemble that of many of Copano's peers in terms of measuring the company's ability to generate cash. Adjusted EBITDA (as revised) equals:

- net income (loss);
- *plus* interest and other financing costs, provision for income taxes, depreciation, amortization and impairment expense, non-cash amortization expense associated with commodity derivative instruments, distributions from unconsolidated affiliates, loss on refinancing of unsecured debt and equity-based compensation expense;
- *minus* equity in earnings (loss) from unconsolidated affiliates and unrealized gains (losses) from commodity risk management activities; and
- *plus or minus* other miscellaneous non-cash amounts affecting net income (loss) for the period.

In calculating adjusted EBITDA as revised, Copano no longer adds to EBITDA (earnings before interest, taxes, depreciation and amortization) its share of the depreciation, amortization and impairment expense and interest and other financing costs embedded in equity in earnings (loss) from unconsolidated affiliates; instead, Copano now adds to EBITDA (i) other non-cash amounts affecting net income (loss) for the period, (ii) non-cash amortization expense associated with commodity derivative instruments, (iii) loss on refinancing of unsecured debt and (iv) distributions from unconsolidated affiliates.

Copano believes that the revised calculation of adjusted EBITDA is a more effective tool for its management in evaluating operating performance for several reasons. Although Copano's historical method for calculating adjusted EBITDA was useful in assessing the performance of Copano's assets (including its unconsolidated affiliates) without regard to financing methods, capital structure or historical cost basis, the prior calculation was not as useful in evaluating the core performance of its assets and their ability to generate cash because adjustments for a number of non-cash expenses and other non-cash and non-operating items were not reflected in the calculation, and the impact of cash distributions from unconsolidated affiliates was likewise not reflected. Additionally, Copano believes that the revised calculation of adjusted EBITDA is more consistent with the method and presentation used by many of its peers and will allow management to better evaluate the company's performance relative to its peer companies.

Also, Copano believes that the revised calculation more effectively represents what lenders and debt holders, as well as industry analysts and many of its unitholders, have indicated is useful in assessing Copano's core performance and outlook and comparing Copano to other companies in its industry. For example, Copano believes that adjusted EBITDA as revised may provide investors and analysts with a more useful tool for evaluating the company's leverage because it more closely resembles Consolidated EBITDA (as defined under Copano's revolving credit facility), which is used by lenders to calculate financial covenants. Consolidated EBITDA differs from adjusted EBITDA in that it includes further adjustments to (i) reflect the pro forma effects of material acquisitions and dispositions and (ii) in the case of leverage ratio calculations, includes projected EBITDA from significant capital projects under construction.

Total Distributable Cash Flow. Commencing with the second quarter of 2011, Copano presents total distributable cash flow as net income (loss) plus all adjustments included in the adjusted EBITDA calculation described above and minus: (i) interest expense, (ii) current tax expense and (iii) maintenance capital expenditures. Although Copano has revised its presentation of total distributable cash flow, the components of the calculation have not changed, except that total distributable cash flow now eliminates the impact of any loss on refinancing of unsecured debt because such losses do not reduce operating cash flow.

Houston-based Copano Energy, L.L.C. is a midstream natural gas company with operations in Texas, Oklahoma, Wyoming and Louisiana. Its assets include approximately 6,400 miles of active natural gas gathering and transmission pipelines, 340 miles of NGL pipelines and ten natural gas processing plants, with more than one billion cubic feet per day of combined processing capacity and 22,000 barrels per day of fractionation capacity. For more information, please visit www.copanoenergy.com.

This press release includes "forward-looking statements," as defined by the Securities and Exchange Commission. Statements that address activities or events that Copano believes will or may occur in the future are forward-looking statements. These statements include, but are not limited to, statements about future producer activity and Copano's total distributable cash flow and distribution coverage. These statements are based on management's experience and perception of historical trends, current conditions, expected future developments and other factors management believes are reasonable. Important factors that could cause actual results to differ materially from those in the forward-looking statements include, without limitation, the following risks and uncertainties, many of which are beyond Copano's control: The volatility of prices and market demand for natural gas and NGLs; Copano's ability to continue to obtain new sources of natural gas supply and retain its key customers; the impact on volumes and resulting cash flow of technological, economic and other uncertainties inherent in estimating future production and producers' ability to drill and successfully complete and attach new natural gas supplies and the availability of downstream transportation systems and other facilities for natural gas and NGLs; higher construction costs or project delays due to inflation, limited availability of required resources, or the effects of environmental, legal or other uncertainties; 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 Copano's filings with the Securities and Exchange Commission.

— financial statements to follow —

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COPANO ENERGY, L.L.C. AND SUBSIDIARIES
UNAUDITED CONSOLIDATED STATEMENTS OF OPERATIONS

	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
	(In thousands, except per unit information)			
Revenue:				
Natural gas sales	$ 120,815	$ 87,524	$ 348,538	$ 292,559
Natural gas liquids sales	191,370	118,999	521,129	353,119
Transportation, compression and processing fees	30,337	17,909	82,706	47,539
Condensate and other	11,169	13,272	37,299	41,204
Total revenue	353,691	237,704	989,672	734,421
Costs and expenses:				
Cost of natural gas and natural gas liquids(1)	281,858	174,461	779,986	551,939
Transportation (1)	6,991	5,340	19,202	16,619
Operations and maintenance	16,091	13,004	46,953	38,337
Depreciation, amortization and impairment	21,911	15,218	56,143	46,002
General and administrative	10,031	9,869	34,530	31,311
Taxes other than income	1,502	1,315	4,029	3,658
Equity in loss (earnings) from unconsolidated affiliates	161,589	(2,049)	158,581	19,788
Total costs and expenses	499,973	217,158	1,099,424	707,654
Operating (loss) income	(146,282)	20,546	(109,752)	26,767
Other income (expense):				
Interest and other income	16	15	31	59
Loss on refinancing of unsecured debt	—	—	(18,233)	—
Interest and other financing costs	(11,080)	(12,943)	(34,450)	(41,239)
(Loss) income before income taxes	(157,346)	7,618	(162,404)	(14,413)
Provision for income taxes	(390)	(320)	(1,161)	(660)
Net (loss) income	(157,736)	7,298	(163,565)	(15,073)
Preferred unit distributions	(8,279)	(7,500)	(24,235)	(7,500)
Net loss to common units	$ (166,015)	$ (202)	$ (187,800)	$ (22,573)
Basic and diluted net loss per common unit	$ (2.51)	$ —	$ (2.84)	$ (0.36)
Weighted average number of common units	66,246	65,658	66,125	63,193
Distributions declared per common unit	$ 0.575	$ 0.575	$ 1.725	$ 1.725

(1) Exclusive of operations and maintenance and depreciation, amortization and impairment shown separately below.

COPANO ENERGY, L.L.C. AND SUBSIDIARIES
UNAUDITED CONSOLIDATED STATEMENTS OF CASH FLOWS

	Nine Months Ended September 30,	
	2011	2010
Cash Flows From Operating Activities:	(In thousands)	
Net loss	$ (163,565)	$ (15,073)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depreciation, amortization and impairment	56,143	46,002
Amortization of debt issue costs	2,855	2,773
Equity in loss from unconsolidated affiliates	158,581	19,788
Distributions from unconsolidated affiliates	17,961	16,999
Loss on refinancing of unsecured debt	18,233	—
Non-cash gain on risk management activities, net	(4,723)	(555)
Equity-based compensation	7,445	7,118
Deferred tax provision	253	(19)
Other non-cash items	(86)	(458)
Changes in assets and liabilities, net of acquisitions:		
Accounts receivable	(11,132)	10,586
Prepayments and other current assets	(2,952)	2,135
Risk management activities	11,353	10,766
Accounts payable	17,459	(6,518)
Other current liabilities	14,964	945
Net cash provided by operating activities	122,789	94,489
Cash Flows From Investing Activities:		
Additions to property, plant and equipment	(175,323)	(101,265)
Additions to intangible assets	(5,316)	(2,259)
Acquisitions	(16,084)	—
Investments in unconsolidated affiliates	(105,111)	(11,186)
Distributions from unconsolidated affiliates	2,368	2,555
Escrow cash	6	—
Proceeds from sale of assets	248	279
Other	98	280
Net cash used in investing activities	(299,114)	(111,596)
Cash Flows From Financing Activities:		
Proceeds from long-term debt	725,000	80,000
Repayment of long-term debt	(412,665)	(350,000)
Payments of premiums and expenses on redemption of unsecured debt	(14,572)	-
Deferred financing costs	(15,743)	(995)
Distributions to unitholders	(114,834)	(107,612)
Proceeds from issuance of Series A convertible preferred units, net of underwriting discounts and commissions of $8,935	—	291,065
Proceeds from public offering of common units, net of underwriting discounts and commissions of $7,223	—	164,786
Equity offering costs	(4)	(6,236)
Proceeds from option exercises	2,747	3,188
Net cash provided by financing activities	169,929	74,196
Net (decrease) increase in cash and cash equivalents	(6,396)	57,089
Cash and cash equivalents, beginning of year	59,930	44,692
Cash and cash equivalents, end of period	$ 53,534	$ 101,781

COPANO ENERGY, L.L.C. AND SUBSIDIARIES
UNAUDITED CONSOLIDATED BALANCE SHEETS

	September 30, 2011	December 31, 2010
	(In thousands, except unit information)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 53,534	$ 59,930

Accounts receivable, net	108,339	96,662
Risk management assets	12,101	7,836
Prepayments and other current assets	8,311	5,179
Total current assets	182,285	169,607
Property, plant and equipment, net	1,078,948	912,157
Intangible assets, net	179,992	188,585
Investments in unconsolidated affiliates	529,958	604,304
Escrow cash	1,850	1,856
Risk management assets	17,128	11,943
Other assets, net	27,739	18,541
Total assets	$ 2,017,900	$ 1,906,993

LIABILITIES AND MEMBERS' CAPITAL

Current liabilities:		
Accounts payable	$ 140,792	$ 117,706
Accrued interest	19,945	10,621
Accrued tax liability	892	913
Risk management liabilities	7,285	9,357
Other current liabilities	33,948	14,495
Total current liabilities	202,862	153,092
Long term debt (includes $0 and $546 bond premium as of September 30, 2011 and December 31, 2010, respectively)	904,525	592,736
Deferred tax liability	2,135	1,883
Risk management and other noncurrent liabilities	2,150	4,525
Commitments and contingencies (Note 9)		
Members' capital:		
Series A convertible preferred units, no par value, 11,399,097 units and 10,585,197 units issued and outstanding as of September 30, 2011 and December 31, 2010, respectively	285,168	285,172
Common units, no par value, 66,270,176 units and 65,915,173 units issued and outstanding as of September 30, 2011 and December 31, 2010, respectively	1,164,399	1,161,652
Paid in capital	59,250	51,743
Accumulated deficit	(592,676)	(313,454)
Accumulated other comprehensive loss	(9,913)	(30,356)
	906,228	1,154,757
Total liabilities and members' capital	$ 2,017,900	$ 1,906,993

COPANO ENERGY, L.L.C. AND SUBSIDIARIES
UNAUDITED RESULTS OF OPERATIONS

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
	($ In thousands)			
Total segment gross margin(1)	$ 64,842	$ 57,903	$ 190,484	$ 165,863
Operations and maintenance expenses	16,091	13,004	46,953	38,337
Depreciation, amortization and impairment	21,911	15,218	56,143	46,002
General and administrative expenses	10,031	9,869	34,530	31,311
Taxes other than income	1,502	1,315	4,029	3,658
Equity in loss (earnings) from unconsolidated affiliates(2)	161,589	(2,049)	158,581	19,788
Operating (loss) income	(146,282)	20,546	(109,752)	26,767
Loss on refinancing of unsecured debt	—	—	(18,233)	—
Interest and other financing costs, net	(11,064)	(12,928)	(34,419)	(41,180)
Provision for income taxes	(390)	(320)	(1,161)	(660)
Net (loss) income	(157,736)	7,298	(163,565)	(15,073)
Preferred unit distributions	(8,279)	(7,500)	(24,235)	(7,500)
Net loss to common units	$ (166,015)	$ (202)	$ (187,800)	$ (22,573)

Total segment gross margin:				
Texas	$ 44,540	$ 31,218	$ 135,685	$ 90,134
Oklahoma	27,876	23,010	79,623	69,106
Rocky Mountains(3)	432	1,091	2,245	3,342
Segment gross margin	72,848	55,319	217,553	162,582
Corporate and other(4)	(8,006)	2,584	(27,069)	3,281
Total segment gross margin(1)	$ 64,842	$ 57,903	$ 190,484	$ 165,863
Segment gross margin per unit:				
Texas:				
Service throughput ($/MMBtu)	$ 0.63	$ 0.58	$ 0.71	$ 0.57
Oklahoma:				
Service throughput ($/MMBtu)	$ 1.05	$ 0.93	$ 1.04	$ 0.97
Volumes:				
Texas: (5)				
Service throughput (MMBtu/d)(6)	765,744	590,116	694,802	577,678
Pipeline throughput (MMBtu/d)	463,321	319,538	436,210	321,450
Plant inlet volumes (MMBtu/d)	686,398	516,949	612,405	481,285
NGLs produced (Bbls/d)	30,904	19,685	27,040	17,818
Oklahoma:(7)				
Service throughput (MMBtu/d)(6)	288,440	270,184	286,320	259,710
Plant inlet volumes (MMBtu/d)	158,070	156,676	160,737	156,771
NGLs produced (Bbls/d)	17,453	16,541	17,498	16,180
Capital Expenditures:				
Maintenance capital expenditures	$ 3,510	$ 3,290	$ 11,111	$ 6,370
Expansion capital expenditures	82,675	29,290	203,576	101,232
Total capital expenditures	$ 86,185	$ 32,580	$ 214,687	$ 107,602
Operations and maintenance expenses:				
Texas	$ 9,082	$ 6,779	$ 26,815	$ 20,845
Oklahoma	6,930	6,163	19,943	17,266
Rocky Mountains	79	62	195	226
Total operations and maintenance expenses	$ 16,091	$ 13,004	$ 46,953	$ 38,337

(1) Total segment gross margin is a non-GAAP financial measure. Please read "— How We Evaluate Our Operations" for a reconciliation of total segment gross margin to its most directly comparable GAAP measure of operating income.

(2) Includes results and volumes associated with our unconsolidated affiliates. The following table summarizes the throughput for the periods indicated:

		Three Months Ended September 30,		Nine Months Ended September 30,	
		2011	2010	2011	2010
Bighorn and Fort Union(a)	MMBtu/d	670,543	913,730	595,302	914,967
Southern Dome					
Plant inlet	MMBtu/d	11,970	12,338	11,630	13,046
NGLs produced	Bbls/d	429	444	418	466
Webb Duval(b)	MMBtu/d	48,628	53,668	48,705	56,145
Eagle Ford Gathering	MMBtu/d	58,295	—	58,295	—
Liberty Pipeline Group	Bbls/d	4,252	—	4,252	—

(a) The volume decline is primarily due to certain Fort Union shippers diverting gas volumes to TransCanada's Bison Pipeline upon its start up in January 2011. Fort Union volumes do not reflect an additional 223,557 MMBtu/d and 279,918 MMBtu/d in long-term contractually committed volumes that Fort Union did not gather but which were the basis of payments received by Fort Union for the three and nine months ended September 30, 2011, respectively.

(b) Net of intercompany volumes.

(3) Rocky Mountains segment gross margin includes results from producer services, including volumes purchased for resale, volumes gathered under firm capacity gathering agreements with Fort Union, volumes transported using our firm capacity agreements with Wyoming Interstate Gas Company and compressor rental services provided to Bighorn. Excludes results and volumes associated with our interest in Bighorn and Fort Union.
(4) Corporate and other includes results attributable to our commodity risk management activities.
(5) 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.
(6) "Service throughput" means the volume of natural gas delivered to our wholly owned processing plants by third-party pipelines plus our "pipeline throughput," which is the volume of natural gas transported or gathered through our pipelines.
(7) Plant inlet volumes and NGLs produced represent total volumes processed and produced by the Oklahoma segment at all plants, including plants owned by the Oklahoma segment and plants owned by third parties.

COPANO ENERGY, L.L.C. AND SUBSIDIARIES
UNAUDITED NON GAAP FINANCIAL MEASURES

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
	($ In thousands)			
Reconciliation of total segment gross margin to operating (loss) income:				
Operating (loss) income	$ (146,282)	$ 20,546	$ (109,752)	$ 26,767
Add:	16,091	13,004	46,953	38,337
Operations and maintenance expenses				
Depreciation, amortization and impairment	21,911	15,218	56,143	46,002
General and administrative expenses	10,031	9,869	34,530	31,311
Taxes other than income	1,502	1,315	4,029	3,658
Equity in loss (earnings) from unconsolidated affiliates	161,589	(2,049)	158,581	19,788
Total segment gross margin	$ 64,842	$ 57,903	$ 190,484	$ 165,863
Reconciliation of EBITDA, adjusted EBITDA and total distributable cash flow to net (loss) income:				
Net (loss) income	$ (157,736)	$ 7,298	$ (163,565)	$ (15,073)
Add:	21,911	15,218	56,143	46,002
Depreciation, amortization and impairment				
Interest and other financing costs	11,080	12,943	34,450	41,239
Provision for income taxes	390	320	1,161	660
EBITDA	(124,355)	35,779	(71,811)	72,828
Add:	7,442	8,163	22,069	24,211
Amortization of commodity derivative options				
Distributions from unconsolidated affiliates	6,757	6,563	20,329	19,554
Loss on refinancing of unsecured debt	—	—	18,233	—
Equity-based compensation	2,093	2,448	9,184	7,849
Equity in loss (earnings) from unconsolidated affiliates	161,589	(2,049)	158,581	19,788
Unrealized (gain) loss from commodity risk management activities	(2,332)	389	(2,695)	150
Other non-cash operating items	576	(295)	(272)	1,933
Adjusted EBITDA	51,770	50,998	153,618	146,313
Less:	(11,029)	(11,856)	(33,623)	(39,171)
Interest expense				
Current income tax expense and other	(305)	(141)	(929)	(740)
Maintenance capital expenditures	(3,510)	(3,290)	(11,111)	(6,370)
Total distributable cash flow	$ 36,926	$ 35,711	$ 107,955	$ 100,032

	Three Months Ended September 30,	
	2011	2010
	(In thousands, except per unit information)	

Reconciliation of adjusted net income and adjusted net income per unit:

Net loss to common units	$ (166,015)	$ (202)
Non-cash impairment charge	170,000	—
Adjusted net income to common units	$ 3,985	$ (202)
Diluted net loss per common unit	$ (2.51)	$ —
Diluted adjusted net income per common unit	$ 0.06	$ —
Weighted average number of diluted common units	66,246	65,658
Restricted units, phantom units, options, unit appreciation rights and contingent units	838	—
Adjusted weighted average number of diluted common units	67,084	65,658

SOURCE Copano Energy, L.L.C.