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

FORM 10-Q

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

For the quarterly period ended September 30, 2010

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: 1-33266

DUNCAN ENERGY PARTNERS L.P.

(Exact name of Registrant as Specified in Its Charter)

Delaware	**20-5639997**
(State or Other Jurisdiction of Incorporation or Organization)	(I.R.S. Employer Identification No.)

1100 Louisiana Street, 10th Floor
Houston, Texas 77002
(Address of Principal Executive Offices, Including Zip Code)

(713) 381-6500
(Registrant's Telephone Number, Including Area Code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes ☑ No o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

Yes o No o

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.

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes o No ☑

There were 57,733,076 common units of Duncan Energy Partners L.P. outstanding at November 1, 2010. Our common units trade on the New York Stock Exchange under the ticker symbol “DEP.”

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PART I. FINANCIAL INFORMATION.

Item 1. ***Financial Statements.***

DUNCAN ENERGY PARTNERS L.P.
UNAUDITED CONDENSED CONSOLIDATED BALANCE SHEETS
(Dollars in millions)

	September 30, 2010	December 31, 2009
ASSETS		
Current assets:		
Cash and cash equivalents	$ 18.4	$ 3.9
Accounts receivable – trade, net of allowance for doubtful accounts	67.6	77.7
Accounts receivable – related parties	26.2	54.5
Gas imbalance receivables	12.7	9.8
Inventories	10.2	10.5
Prepaid and other current assets	15.2	9.8
Total current assets	150.3	166.2
Property, plant and equipment, net	5,071.4	4,549.6
Investment in Evangeline	6.1	5.6
Intangible assets, net of accumulated amortization of $48.8 at September 30, 2010 and $42.6 at December 31, 2009	39.1	43.8
Goodwill	4.9	4.9
Other assets	0.2	0.7
Total assets	$ 5,272.0	$ 4,770.8
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable – trade	$ 97.9	$ 54.5
Accounts payable – related parties	27.5	13.6
Accrued product payables	48.8	59.9
Accrued property taxes	13.1	9.1
Accrued taxes – other	12.8	8.4
Other current liabilities	22.4	18.9
Total current liabilities	222.5	164.4
Long-term debt: (see Note 9)		
Bank credit facilities	529.8	457.3
Loan Agreement with EPO	125.0	--
Total long-term debt	654.8	457.3
Deferred tax liabilities	5.9	5.8
Other long-term liabilities	6.8	6.4
Commitments and contingencies		
Equity:		
Duncan Energy Partners L.P. partners' equity: (see Note 10)		
Limited partners:		
Common units (57,733,076 common units outstanding at September 30, 2010 and 57,676,987 common units outstanding at December 31, 2009)	760.0	766.6
General partner	0.1	0.2
Accumulated other comprehensive loss	(0.1)	(5.4)
Total Duncan Energy Partners L.P. partners' equity	760.0	761.4
Noncontrolling interest in subsidiaries: (see Note 11)		
DEP I Midstream Businesses – Parent	614.1	487.3
DEP II Midstream Businesses – Parent	3,007.9	2,888.2
Total noncontrolling interest	3,622.0	3,375.5
Total equity	4,382.0	4,136.9
Total liabilities and equity	$ 5,272.0	$ 4,770.8

See Notes to Unaudited Condensed Consolidated Financial Statements.

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DUNCAN ENERGY PARTNERS L.P.
UNAUDITED CONDENSED STATEMENTS OF CONSOLIDATED OPERATIONS
(Dollars in millions)

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2010	**2009**	**2010**	**2009**
Revenues:				
Third parties	$ 112.0	$ 116.0	$ 394.4	$ 336.5
Related parties	171.7	128.6	445.1	391.6
Total revenues (see Note 12)	283.7	244.6	839.5	728.1
Costs and Expenses:				
Operating costs and expenses:				
Third parties	220.6	178.6	650.4	551.0
Related parties	47.9	42.2	130.4	124.7
Total operating costs and expenses	268.5	220.8	780.8	675.7
General and administrative costs:				
Third parties	0.5	0.3	2.7	1.0
Related parties	5.9	2.9	13.4	7.8
Total general and administrative costs	6.4	3.2	16.1	8.8
Total costs and expenses (see Note 12)	274.9	224.0	796.9	684.5
Equity in income of Evangeline	0.3	0.5	0.5	1.0
Operating income	9.1	21.1	43.1	44.6
Other income (expense):				
Interest expense	(3.0)	(3.4)	(9.3)	(10.6)
Other, net	0.1	--	0.1	0.1
Total other expense, net	(2.9)	(3.4)	(9.2)	(10.5)
Income before benefit from (provision for) income taxes	6.2	17.7	33.9	34.1
Benefit from (provision for) income taxes	(0.5)	0.1	(0.7)	(0.8)
Net income	5.7	17.8	33.2	33.3
Net loss (income) attributable to noncontrolling interest: (see Note 11)				
DEP I Midstream Businesses - Parent	(7.4)	(5.7)	(19.9)	(10.3)
DEP II Midstream Businesses - Parent	22.3	12.7	51.8	44.9
Total net loss attributable to noncontrolling interest	14.9	7.0	31.9	34.6
Net income attributable to Duncan Energy Partners L.P.	$ 20.6	$ 24.8	$ 65.1	$ 67.9
Allocation of net income attributable to Duncan Energy Partners L.P.:				
Limited partners	$ 20.4	$ 24.6	$ 64.6	$ 67.4
General partner	$ 0.2	$ 0.2	$ 0.5	$ 0.5
Basic and diluted earnings per unit (see Note 14)	$ 0.36	$ 0.43	$ 1.12	$ 1.17

See Notes to Unaudited Condensed Consolidated Financial Statements.

DUNCAN ENERGY PARTNERS L.P.
UNAUDITED CONDENSED STATEMENTS OF CONSOLIDATED COMPREHENSIVE INCOME
(Dollars in millions)

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2010	**2009**	**2010**	**2009**
Net income	$ 5.7	$ 17.8	$ 33.2	$ 33.3
Other comprehensive income:				
Cash flow hedges:				
Commodity derivative instrument losses during period	--	--	(0.1)	--
Interest rate derivative instrument losses during period	(0.1)	(1.1)	(0.2)	(0.9)
Reclassification adjustment for losses included in net income related to interest rate derivative instruments	1.8	1.8	5.6	4.7
Total cash flow hedges	1.7	0.7	5.3	3.8
Comprehensive income	7.4	18.5	38.5	37.1
Comprehensive loss (income) attributable to noncontrolling interest:				
DEP I Midstream Businesses – Parent	(7.4)	(5.7)	(19.9)	(10.3)
DEP II Midstream Businesses – Parent	22.3	12.7	51.8	44.9
Total comprehensive loss attributable to noncontrolling interest	14.9	7.0	31.9	34.6
Comprehensive income attributable to Duncan Energy Partners L.P.	$ 22.3	$ 25.5	$ 70.4	$ 71.7

See Notes to Unaudited Condensed Consolidated Financial Statements.

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DUNCAN ENERGY PARTNERS L.P.
UNAUDITED CONDENSED STATEMENTS OF CONSOLIDATED CASH FLOWS
(Dollars in millions)

	For the Nine Months Ended September 30, 2010	For the Nine Months Ended September 30, 2009
Operating activities:		
Net income	$ 33.2	$ 33.3
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion	152.5	139.1
Equity in income of Evangeline	(0.5)	(1.0)
Loss (gains) from asset sales and related transactions	8.0	(0.4)
Deferred income tax expense	0.1	(0.2)
Non-cash asset impairment charges	1.5	--
Changes in fair market value of derivative instruments	--	(0.1)
Net effect of changes in operating accounts (see Note 17)	18.2	(33.4)
Net cash flows provided by operating activities	213.0	137.3
Investing activities:		
Capital expenditures	(649.6)	(306.5)
Contributions in aid of construction costs	6.9	4.2
Proceeds from asset sales and related transactions	2.3	0.9
Other, including loans to EPO (see Note 13)	45.5	(0.8)
Cash used in investing activities	(594.9)	(302.2)
Financing activities:		
Borrowings under bank agreements	138.1	60.6
Repayments of debt under bank agreements	(65.6)	(82.1)
Borrowings under Loan Agreement with EPO (see Note 9)	125.0	--
Debt issuance costs	--	(0.4)
Cash distributions to our unitholders and general partner	(78.0)	(63.3)
Cash distributions to EPO as noncontrolling interest	(81.0)	(42.1)
Cash contributions from EPO as noncontrolling interest (see Note 11)	356.7	311.1
Net cash proceeds from the issuance of common units	1.2	137.4
Repurchase of our common units from EPO (see Note 10)	--	(137.4)
Cash provided by financing activities	396.4	183.8
Net changes in cash and cash equivalents	14.5	18.9
Cash and cash equivalents, January 1	3.9	13.0
Cash and cash equivalents, September 30	$ 18.4	$ 31.9

See Notes to Unaudited Condensed Consolidated Financial Statements.

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DUNCAN ENERGY PARTNERS L.P.
UNAUDITED CONDENSED STATEMENTS OF CONSOLIDATED EQUITY
(Dollars in millions)

	Duncan Energy Partners L.P.				
	Limited Partners	**General Partner**	**Accumulated Other Comprehensive Income (Loss)**	**Noncontrolling Interest in Subsidiaries**	**Total**
Balance, December 31, 2009	$ 766.6	$ 0.2	$ (5.4)	$ 3,375.5	$ 4,136.9
Net income	64.6	0.5	--	(31.9)	33.2
Amortization of equity awards	4.9	--	--	--	4.9
Net cash proceeds from the issuance of common units	1.2	--	--	--	1.2
Cash distributions to unitholders and general partner	(77.5)	(0.5)	--	--	(78.0)
Cash distributions to EPO as noncontrolling interest	--	--	--	(81.0)	(81.0)
Cash contributions from EPO as noncontrolling interest	--	--	--	356.7	356.7
Change in value of cash flow hedges	--	--	5.3	--	5.3
Other	0.2	(0.1)	--	2.7	2.8
Balance, September 30, 2010	$ 760.0	$ 0.1	$ (0.1)	$ 3,622.0	$ 4,382.0

	Duncan Energy Partners L.P.				
	Limited Partners	**General Partner**	**Accumulated Other Comprehensive Income (Loss)**	**Noncontrolling Interest in Subsidiaries**	**Total**
Balance, December 31, 2008	$ 762.0	$ 0.4	$ (9.6)	$ 3,091.4	$ 3,844.2
Net income	67.4	0.5	--	(34.6)	33.3
Amortization of equity awards	1.6	*	--	--	1.6
Net cash proceeds from the issuance of common units	137.4	--	--	--	137.4
Common units repurchased from EPO and retired	(137.4)	--	--	--	(137.4)
Cash distributions to unitholders and general partner	(62.8)	(0.5)	--	--	(63.3)
Cash distributions to EPO as noncontrolling interest	--	--	--	(42.1)	(42.1)
Cash contributions from EPO as noncontrolling interest	--	--	--	311.1	311.1
Change in value of cash flow hedges	--	--	3.8	--	3.8
Other	(0.1)	--	--	1.6	1.5
Balance, September 30, 2009	$ 768.1	$ 0.4	$ (5.8)	$ 3,327.4	$ 4,090.1

See Notes to Unaudited Condensed Consolidated Financial Statements.
*Amount is immaterial.

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Except unit-related amounts, or as noted within the context of each footnote disclosure, the dollar amounts presented in the tabular data within these footnotes are stated in millions of dollars.

SIGNIFICANT RELATIONSHIPS REFERENCED IN THESE NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Unless the context requires otherwise, references to “we,” “us,” “our,” or “Duncan Energy Partners” are intended to mean the business and operations of Duncan Energy Partners L.P. and its consolidated subsidiaries. References to “DEP GP” mean DEP Holdings, LLC, which is our general partner. DEP GP is responsible for managing the business and operations of Duncan Energy Partners. References to “DEP OLP” mean DEP Operating Partnership, L.P., which is a wholly owned subsidiary of Duncan Energy Partners. Duncan Energy Partners conducts substantially all of its business through DEP OLP and its consolidated subsidiaries.

References to “Enterprise Products Partners” mean the business and operations of Enterprise Products Partners L.P. and its consolidated subsidiaries. Enterprise Products Partners is a publicly traded Delaware limited partnership, the common units of which are listed on the New York Stock Exchange (“NYSE”) under the ticker symbol “EPD.” References to “EPGP” mean Enterprise Products GP, LLC, which is the general partner of Enterprise Products Partners. References to “EPO” mean Enterprise Products Operating LLC, which is a wholly owned subsidiary of Enterprise Products Partners. Enterprise Products Partners conducts substantiall y all of its business through EPO and its consolidated subsidiaries. EPO beneficially owns 100% of DEP GP and currently owns 58.5% of our common units. Enterprise Products Partners consolidates our financial statements with its own.

References to “Holdings” mean Enterprise GP Holdings L.P., a publicly traded Delaware limited partnership, the units of which are listed on the NYSE under the ticker symbol “EPE.” Holdings owns EPGP. The general partner of Holdings is EPE Holdings, LLC (“EPE Holdings”), which is a wholly owned subsidiary of Dan Duncan LLC. On September 3, 2010, Holdings and Enterprise Products Partners entered into an Agreement and Plan of Merger that would, if approved by the Holdings’ unitholders, result in the merger of Holdings with a wholly owned subsidiary of Enterprise Products Partners through a unit-for-unit exchange.

The membership interests of Dan Duncan LLC are owned of record by a voting trust formed on April 26, 2006, pursuant to the Dan Duncan LLC Voting Trust Agreement dated April 26, 2006 (the “DD LLC Voting Trust Agreement”), among Dan Duncan LLC and Dan L. Duncan (as the record owner of all of the membership interests of Dan Duncan LLC immediately prior to the entering into of the DD LLC Voting Trust Agreement and as the initial sole voting trustee).

Immediately upon Mr. Duncan’s death on March 29, 2010, voting and dispositive control of all of the membership interests of Dan Duncan LLC was transferred pursuant to the DD LLC Voting Trust Agreement to three voting trustees. The current voting trustees under the DD LLC Voting Trust Agreement (the “DD LLC Trustees”) are: (i) Randa Duncan Williams, Mr. Duncan’s oldest daughter, who is also a director of EPE Holdings; (ii) Dr. Ralph S. Cunningham, who is currently the President and Chief Executive Officer (“CEO”) of EPE Holdings; and (iii) Richard H. Bachmann, who is currently an Executive Vice President, the Chief Legal Officer and Secretary of EPGP and one of three managers of Dan Duncan LLC. Dr. Cunningham and Mr. Bachmann also serve as directors of EPE Holdings.

The DD LLC Voting Trust Agreement requires that there always be two “Independent Voting Trustees” serving. If Mr. Bachmann or Dr. Cunningham fail to qualify or cease to serve, then the substitute or successor Independent Voting Trustee(s) will be appointed by the then-serving Independent Voting Trustee, provided that if no Independent Voting Trustee is then serving or if a vacancy in a trusteeship of an Independent Voting Trustee is not filled within ninety days of the vacancy’s occurrence, the CEO of EPGP, currently Michael A. Creel, will appoint the successor Independent Voting Trustee(s).

The DD LLC Voting Trust Agreement also provides for a “Duncan Voting Trustee.” The Duncan Voting Trustee is appointed by the children of Mr. Duncan acting by a majority or, if less than three children of Mr. Duncan are then living, unanimously. If for any reason no descendent of Mr. Duncan is appointed as the Duncan Voting Trustee, then such trusteeship will remain vacant until such time as a Duncan Voting Trustee is appointed in the manner provided above. If a Duncan Voting Trustee for any reason ceases to serve, his or her successor shall be appointed by the children of Mr. Duncan acting by majority or, if less than three children of Mr. Duncan are then living, unanimously. Ms. Williams is currently the Duncan Voting Trustee.

The estate of Mr. Duncan became the sole member party to the DD LLC Voting Trust Agreement upon the death of Mr. Duncan on March 29, 2010. For all purposes whatsoever, the DD LLC Trustees are required to treat the member party to the DD LLC Voting Trust Agreement as the beneficial owner of the membership interests of Dan Duncan LLC. However, the DD LLC Trustees collectively are the record owners of the Dan Duncan LLC membership interests and possess and are entitled to exercise all rights and powers of absolute ownership thereof and to vote, assent or consent with respect thereto and to take party in and consent to any corporate or members' actions (except those actions, if any, to which the DD LLC Trustees may not legally consent) and subject to the provision s of the DD LLC Voting Trust Agreement, to receive distributions on the Dan Duncan LLC membership interests. Except as otherwise provided in the DD LLC Voting Trust Agreement, all actions taken by the DD LLC Trustees are by majority vote.

The DD LLC Trustees serve in such capacity without compensation, but they are entitled to incur reasonable charges and expenses deemed necessary and proper for administering the DD LLC Voting Trust Agreement and to reimbursement and indemnification.

The DD LLC Voting Trust Agreement will terminate when (i) the descendants of Mr. Duncan, and entities directly or indirectly controlled by or held for the benefit of any such descendant, no longer own any capital stock of EPCO (as defined below); or (ii) upon such earlier date designated by the DD LLC Trustees by an instrument in writing delivered to the member party to the DD LLC Voting Trust Agreement.

On April 27, 2010, the independent co-executors for the estate of Mr. Duncan were appointed by the probate court. The independent co-executors are Mr. Bachmann, Dr. Cunningham and Ms. Williams, who are the same persons as the current DD LLC Trustees and voting trustees under a separate voting trust agreement relating to a majority of EPCO's outstanding shares with voting rights (as more fully described below).

References to "EPCO" mean Enterprise Products Company (formerly EPCO, Inc.) and its privately held affiliates. Prior to Mr. Duncan's death, we, Enterprise Products Partners, EPO, DEP GP, EPGP, Holdings and EPE Holdings were affiliates under the common control of Mr. Duncan, since he was the controlling shareholder of EPCO and the controlling member of Dan Duncan LLC. A majority of the outstanding voting capital stock of EPCO is owned of record by a voting trust formed on April 26, 2006, pursuant to the EPCO Inc. Voting Trust Agreement (the "EPCO Voting Trust Agreement"), among EPCO and Mr. Duncan (as the record owner of a majority of the outstanding voting capital stock of EPCO immediately prior to the entering into of the EPCO Voting T rust Agreement and as the initial sole voting trustee).

Immediately upon Mr. Duncan's death, voting and dispositive control of such majority of the outstanding voting capital stock of EPCO was transferred pursuant to the EPCO Voting Trust Agreement to three voting trustees (the "EPCO Trustees"). The current EPCO Trustees are: (i) Ms. Williams, who serves as Chairman of EPCO; (ii) Dr. Cunningham, who serves as a Vice Chairman of EPCO; and (iii) Mr. Bachmann, who serves as the President, CEO and Chief Legal Officer of EPCO. Ms. Williams, Dr. Cunningham and Mr. Bachmann are also currently directors of EPCO. The current EPCO Trustees are the same as the current DD LLC Trustees, which control Dan Duncan LLC. The current EPCO Trustees are also the same persons as the individuals appointe d on April 27, 2010 as the independent co-executors of the estate of Mr. Duncan.

References to the "DEP I Midstream Businesses" collectively refer to (i) Mont Belvieu Caverns, LLC ("Mont Belvieu Caverns"); (ii) Acadian Gas, LLC ("Acadian Gas"); (iii) Enterprise Lou-Tex

Propylene Pipeline L.P. ("Lou-Tex Propylene"), including its general partner; (iv) Sabine Propylene Pipeline L.P. ("Sabine Propylene"), including its general partner; and (v) South Texas NGL Pipelines, LLC ("South Texas NGL"). We acquired controlling ownership interests in the DEP I Midstream Businesses from EPO effective February 1, 2007 in a drop down transaction (the "DEP I drop down") in connection with our initial public offering.

References to the "DEP II Midstream Businesses" collectively refer to (i) Enterprise GC, L.P. ("Enterprise GC"); (ii) Enterprise Intrastate L.P. ("Enterprise Intrastate"); and (iii) Enterprise Texas Pipeline LLC ("Enterprise Texas"). We acquired controlling ownership interests in the DEP II Midstream Businesses from EPO on December 8, 2008 in a drop down transaction (the "DEP II drop down").

References to "Evangeline" mean our aggregate 49.51% equity method investment in Evangeline Gas Pipeline Company, L.P. ("EGP") and Evangeline Gas Corp ("EGC").

References to "Energy Transfer Equity" mean the business and operations of Energy Transfer Equity, L.P. and its consolidated subsidiaries, which include Energy Transfer Partners, L.P. ("ETP") and, effective May 26, 2010, Regency Energy Partners LP ("RGNC"). Energy Transfer Equity is a publicly traded Delaware limited partnership, the common units of which are listed on the NYSE under the ticker symbol "ETE." ETP is a publicly traded Delaware limited partnership, the common units of which are listed on the NYSE under the ticker symbol "ETP." RGNC is a publicly traded Delaware limited partnership, the common units of which are traded on the NASDAQ stock market under the ticker symbol "RGNC." The general partner of Energy Transfer Equity is LE GP, LLC.

References to the "Employee Partnerships" mean EPE Unit L.P., EPE Unit II, L.P., EPE Unit III, L.P., Enterprise Unit L.P. and EPCO Unit L.P. ("EPCO Unit"), collectively, all of which were privately held affiliates of EPCO. The Employee Partnerships were liquidated in August 2010. See Note 3 for additional information.

Note 1. Partnership Operations and Basis of Presentation

General

We are a publicly traded Delaware limited partnership, the common units of which are listed on the NYSE under the ticker symbol "DEP." We were formed by EPO in September 2006 and completed our initial public offering of common units in February 2007. Our business purpose is to acquire, own and operate a diversified portfolio of midstream energy assets and to support the growth objectives of EPO and other affiliates of EPCO that are under common control. We are engaged in the business of (i) NGL transportation, fractionation and marketing; (ii) storage of NGL and petrochemical products; (iii) transportation of petrochemical products; and (iv) the gathering, transportation, marketing and storage of natural gas. Our assets, located primarily in Texas and Louisiana, include: 11,000 m iles of natural gas, NGL and petrochemical pipelines; two NGL fractionation facilities; approximately 18 million barrels ("MMBbls") of leased NGL storage capacity; 8.1 billion cubic feet ("Bcf") of leased natural gas storage capacity; and 34 underground salt dome caverns with over 100 MMBbls of NGL storage capacity. Our assets are integral to EPO's midstream energy operations and are located near significant natural gas production basins such as the Eagle Ford Shale, Barnett Shale and Haynesville Shale plays.

We have three reportable business segments: (i) NGL Pipelines & Services; (ii) Natural Gas Pipelines & Services; and (iii) Petrochemical Services. Our business segments reflect the manner in which these businesses are managed and reviewed by the CEO of our general partner. See Note 12 for additional information regarding our business segments.

We are owned 99.3% by our limited partners and 0.7% by our general partner, DEP GP. At September 30, 2010, EPO owned approximately 58.5% of our limited partner interests and 100% of DEP GP. We, DEP GP, EPO, Enterprise Products Partners, Holdings, EPE Holdings, EPCO and Dan Duncan LLC are affiliates and under the collective common control of the DD LLC Trustees and EPCO Trustees.

We have no employees. All of our operating functions and general and administrative support services are provided by employees of EPCO pursuant to an administrative services agreement (the "ASA") or by other service providers. See Note 13 for information regarding the ASA and related party matters.

We acquired controlling ownership interests in our consolidated subsidiaries through two drop down transactions, the DEP I and DEP II drop downs, that were sponsored by EPO. The following information summarizes the businesses acquired in connection with the DEP I and DEP II drop down transactions.

DEP I Drop Down

Effective February 1, 2007, EPO contributed to us a 66% controlling equity interest in each of the DEP I Midstream Businesses in a drop down transaction. EPO retained the remaining 34% noncontrolling equity interest in each of these businesses.

The following is a brief description of the assets and operations of the DEP I Midstream Businesses:

§ Mont Belvieu Caverns owns 34 underground salt dome storage caverns located in Mont Belvieu, Texas, having an NGL and related product storage capacity of approximately 100 MMBbls, and a brine system with approximately 20 MMBbls of above ground storage capacity and related brine production wells.

§ Acadian Gas is engaged in the gathering, transportation, storage and marketing of natural gas in south Louisiana, utilizing over 1,000 miles of pipelines having an aggregate throughput capacity of 1.0 billion cubic feet per day ("Bcf/d"). Acadian Gas also owns a 49.51% equity interest in Evangeline, which owns a 27-mile natural gas pipeline located in southeast Louisiana.

  In October 2009, we and EPO announced plans for our jointly owned Acadian Gas system to extend its Louisiana intrastate natural gas pipeline system into northwest Louisiana to provide producers in the Haynesville Shale production area with access to additional markets in south Louisiana and connections to nine third-party major interstate natural gas pipelines. This expansion capital project is referred to as the "Haynesville Extension" of the Acadian Gas system. As currently designed, the Haynesville Extension will have the potential capacity to transport up to 2.1 Bcf/d of natural gas from the Haynesville area through a 249-mile pipeline that will connect with our existing Acadian Gas system. The Haynesville Extension is expected to be in service during the third quarter of 2011.

  The total expected cost of the Haynesville Extension is approximately $1.56 billion (including capitalized interest). In June 2010, we agreed to fund 66% of the Haynesville Extension project costs and EPO will fund the remaining 34% of such expenditures; therefore, we estimate that our share of such costs will approximate $1.03 billion. In order to address our funding requirements under the Haynesville Extension project, we entered into new long-term senior unsecured credit facilities having an aggregate borrowing capacity of $1.25 billion in October 2010.

  For information regarding our agreements with EPO related to the Haynesville Extension, see Note 13. For information regarding our $1.25 billion credit facilities, see Note 9.

§ Lou-Tex Propylene owns a 263-mile pipeline used to transport chemical-grade propylene from Sorrento, Louisiana to Mont Belvieu, Texas.

§ Sabine Propylene owns a 21-mile pipeline used to transport polymer-grade propylene from Port Arthur, Texas to a pipeline interconnect in Cameron Parish, Louisiana.

§ South Texas NGL owns a 297-mile pipeline system used to transport NGLs from our Shoup and Armstrong NGL fractionation facilities in south Texas to Mont Belvieu, Texas.

DEP II Drop Down

On December 8, 2008, EPO contributed to us the following controlling equity interests in a second drop down transaction: (i) a 66% voting general partner interest in Enterprise GC, (ii) a 51% voting general partner interest in Enterprise Intrastate and (iii) a 51% voting membership interest in Enterprise Texas. The following is a brief description of the assets and operations of the DEP II Midstream Businesses:

§ Enterprise GC operates and owns: (i) two NGL fractionation facilities, the Shoup and Armstrong facilities, located in south Texas; (ii) a 1,020-mile NGL pipeline system located in south Texas; and (iii) 1,108 miles of natural gas gathering pipelines located in south and west Texas. Enterprise GC's natural gas gathering pipelines include: (i) the 258-mile Big Thicket Gathering System located in southeast Texas; (ii) the 660-mile Waha system located in the Permian Basin of west Texas; and (iii) the 190-mile TPC Offshore gathering system located in south Texas.

§ Enterprise Intrastate operates and owns an undivided 50% interest in the assets comprising the 641-mile Channel natural gas pipeline, which extends from the Agua Dulce Hub in south Texas to Sabine, Texas located on the Texas/Louisiana border.

§ Enterprise Texas owns the 6,560-mile Enterprise Texas natural gas pipeline system, which includes the Sherman Extension and Trinity River Lateral pipelines, and leases the Wilson natural gas storage facility. The Enterprise Texas system, along with the Waha, TPC Offshore and Channel pipeline systems, comprise our Texas Intrastate System.

In July 2010, we completed and placed into service the final segment of our Trinity River Lateral natural gas pipeline, which is a component of our Texas Intrastate System. In total, the Trinity River Lateral pipeline extends approximately 40 miles from the Trinity River Basin north of Arlington, Texas to an interconnect near Justin, Texas with our Sherman Extension pipeline. The Trinity River Lateral provides producers in Tarrant and Denton Counties in north Texas with up to 1 Bcf/d of production takeaway capacity.

Our Texas Intrastate System is strategically located to benefit from increasing natural gas production from the Eagle Ford Shale basin located in south Texas. We are in the process of expanding the system's natural gas gathering and transportation capabilities as well as increasing our storage capacity at Wilson to handle the expected increase in production volumes. EPO is funding 100% of the growth capital spending associated with these expansion projects.

See "DEP II Midstream Businesses – Parent" under Note 11 and "Significant Relationships and Agreements with EPO – Company and Limited Partnership Agreements – DEP II Midstream Businesses" under Note 13 for additional information regarding the DEP II Midstream Businesses.

To the extent that the DEP II Midstream Businesses collectively generate cash sufficient to pay distributions to EPO and us, such cash will be distributed first to us (based on an initial defined investment of $730.0 million) and then to EPO in amounts sufficient to generate an aggregate annualized return on their respective investments. From December 8, 2008 through December 31, 2009, the annualized return was 11.85%. Effective January 1, 2010, the annualized return increased by 2.0% to 12.087%. Distributions in excess of these amounts will be distributed 98% to EPO and 2% to us. Income and loss of the DEP II Midstream Businesses are first allocated to EPO and us based on each entity's percentage interest of 77.4% and 22.6%, respectively , and then in a manner that in part follows the cash distributions.

See Note 11 for detailed information regarding EPO's noncontrolling interest in the DEP I and DEP II Midstream Businesses.

Interim Reporting

Our results of operations for the three and nine months ended September 30, 2010 are not necessarily indicative of results expected for the full year. In our opinion, the accompanying Unaudited

Condensed Consolidated Financial Statements include all adjustments consisting of normal recurring accruals necessary for fair presentation. Although we believe the disclosures in these financial statements are adequate to make the information presented not misleading, certain information and footnote disclosures normally included in annual financial statements prepared in accordance with U.S. generally accepted accounting principles ("GAAP") have been condensed or omitted pursuant to the rules and regulations of the U.S. Securities and Exchange Commission ("SEC"). These Unaudited Condensed Consolidated Financial Statements and the Notes thereto should be read in conjunction with the Audited Consolidated Financial Statements and Notes thereto included in our annual report for the year ended December 31, 2009, as initially filed on Form 10-K on March 1, 2010, and as amended on Form 10-K/A on May 21, 2010 ("2009 F orm 10-K/A") (Commission File No. 1-33266).

Note 2. General Accounting Matters

Estimates

Preparing our financial statements in conformity with GAAP requires management to make estimates and assumptions that affect amounts presented in the financial statements (e.g., assets, liabilities, revenue and expenses) and disclosures regarding contingent assets and liabilities. Our actual results could differ from these estimates. On an ongoing basis, management reviews its estimates based on currently available information. Any future changes in facts and circumstances may require updated estimates, which, in turn, could have a significant impact on our financial statements.

Fair Value Information

Cash and cash equivalents, accounts receivable, accounts payable and accrued expenses and other current liabilities (excluding derivative instruments) are carried at amounts which reasonably approximate their fair values due to their short-term nature. The carrying amounts of our variable-rate debt obligations reasonably approximate their fair values due to their variable interest rates. See Note 4 for fair value information associated with our derivative instruments.

The following table presents the estimated fair values of our financial instruments at the dates indicated:

	September 30, 2010		December 31, 2009	
Financial Instruments	**Carrying Value**	**Fair Value**	**Carrying Value**	**Fair Value**
Financial assets:				
Cash and cash equivalents	$ 18.4	$ 18.4	$ 3.9	$ 3.9
Accounts receivable	106.5	106.5	142.0	142.0
Financial liabilities:				
Accounts payable and accrued expenses	200.1	200.1	145.5	145.5
Other current liabilities (excluding derivative instruments)	22.0	22.0	13.3	13.3
Variable-rate debt	654.8	654.8	457.3	457.3

Recent Accounting Developments

In November 2008, the SEC released a proposed roadmap regarding the potential use by U.S. issuers of financial statements prepared in accordance with International Financial Reporting Standards ("IFRS"). IFRS consist of accounting standards published by the International Accounting Standards Board ("IASB"), which is based in London, England. In February 2010, the SEC expressed its continuing support for a single set of high-quality globally accepted accounting standards and established a general work plan that sets forth areas and factors the SEC will consider before requiring domestic public companies to transition to IFRS. Currently, the Financial Accounting Standards Board (or "FASB," based in Norwalk, Connecticut) and the IASB are working both individually and jo intly on a number of accounting standard convergence projects that, if finalized in 2011, would bring about a significant shift in the accounting and financial reporting landscape. These projects include a broad range of topics such as financial statement presentation, accounting for leases, revenue recognition, financial instruments, consolidations and fair value measurements.

The SEC expects to make a determination in 2011 regarding the mandatory adoption of IFRS, with the expectation that any decision to adopt IFRS will allow U.S. issuers a number of years to transition from current U.S. GAAP. We continue to monitor developments regarding the potential implementation of IFRS and the ongoing convergence projects of the FASB and IASB. We will evaluate the impact that any definitive accounting guidance may have on our financial statements once this information is finalized by the appropriate standard setting organizations, including the SEC.

Note 3. Equity-based Awards

An allocated portion of the fair value of EPCO's equity-based awards is charged to us under the ASA. The following table summarizes the expense we recognized in connection with equity-based awards for the periods indicated:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2010	2009	2010	2009
Restricted unit awards (1)	$ 1.1	$ 0.3	$ 2.7	$ 1.1
Unit option awards (1)	*	*	0.1	0.1
Profits interests awards (1, 2)	1.8	0.1	2.1	0.4
Total compensation expense	$ 2.9	$ 0.4	$ 4.9	$ 1.6

(1) Accounted for as equity-classified awards. The fair value of an equity-classified award is amortized to earnings over the requisite service or vesting period.
(2) The increase between periods is due to the liquidation of the Employee Partnerships in August 2010 (see below).
* Amount is negligible.

We are charged amounts associated with EPCO's long-term incentive plans, including the Duncan Energy Partners L.P. Long-Term Incentive Plan (the "2010 Plan"), and other long-term incentive arrangements. The expense we recognize in connection with equity-classified awards includes amounts associated with the Enterprise Products 1998 Long-Term Incentive Plan and the Amended and Restated 2008 Enterprise Products Long-Term Incentive Plan. EPCO's equity-classified awards also included profits interests in the Employee Partnerships until their liquidation in August 2010.

With the exception of certain amounts recorded in connection with EPCO Unit (one of the Employee Partnerships), we were not responsible for reimbursing EPCO for any of the costs associated with equity awards. Beginning in February 2009, the ASA was amended to provide that we and other affiliates of EPCO would reimburse EPCO for our allocated share of distributions of cash or securities made to the Class B limited partners of EPCO Unit.

The 2010 Plan provides for awards of options to purchase common units, restricted common units, unit appreciation rights, phantom units and distribution equivalent rights to employees, directors or consultants providing services to us and our subsidiaries.

Summary of Long-Term Incentive Awards

The following information is being provided regarding the 2010 Plan and EPCO's other long-term incentive awards under which we have received or may receive an allocation of expense. EPCO has certain plans under which liability-classified awards may be issued. As of September 30, 2010, we have not been allocated any costs of liability-classified awards and therefore have not included any discussion of such plans in these disclosures. EPCO may create additional long-term incentive plans in the future that may result in us receiving an allocation of expense based on services rendered to us by the recipients of such awards. Unless noted otherwise, the following information is presented on a gross basis (i.e., in total to EPCO and its affiliates) with respect to the type of award granted. To the extent applicable, we have noted our estimated share of unrecognized compensation costs of such awards and the weighted-average period of time over which we expect to recognize such expense.

Restricted Unit Awards

Restricted unit awards allow recipients to acquire (at no cost to the recipient apart from service or other conditions) limited partner units once a defined vesting period expires, subject to customary forfeiture provisions. Restricted unit awards may be denominated in our common units or those of Enterprise Products Partners depending on the issuer of the award. Restricted unit awards issued prior to 2010 generally cliff vest four years from the date of grant. Beginning with awards issued in 2010, restricted unit awards are typically subject to graded vesting provisions in which one-fourth of each award vests on the first, second, third and fourth anniversaries of the date of grant. As used in the context of EPCO's long-term incentive plans, the term "restricted unit" repr esents a time-vested unit. Such awards are non-vested until the required service period expires.

The fair value of a restricted unit award is based on the market price per unit of the underlying security on the date of grant. Compensation expense is recognized based on the grant date fair value, net of an allowance for estimated forfeitures, over the requisite service or vesting period.

The following table presents information regarding restricted unit awards for the period indicated:

	Number of Units	Weighted-Average Grant Date Fair Value per Unit (1)
Enterprise Products Partners L.P. restricted unit awards		
Restricted units at December 31, 2009	2,720,882	$ 27.70
Granted (2,3)	1,353,425	$ 32.36
Vested (3)	(339,628)	$ 25.26
Forfeited	(103,558)	$ 29.54
Restricted units at September 30, 2010	3,631,121	$ 29.61
Duncan Energy Partners L.P. restricted unit awards		
Restricted units at December 31, 2009	--	
Granted (3,4)	6,348	$ 25.26
Vested (3)	(6,348)	$ 25.26
Restricted units at September 30, 2010	--	

(1) Determined by dividing the aggregate grant date fair value of awards before an allowance for forfeitures by the number of awards issued.
(2) Aggregate grant date fair value of restricted unit awards denominated in Enterprise Products Partners' common units was $43.8 million based on grant date market prices of Enterprise Products Partners' common units ranging from $32.00 to $38.36 per unit. Estimated forfeiture rates ranging between 4.6% and 17% were applied to these awards.
(3) Includes awards granted to the independent directors of the boards of directors of EPGP and DEP GP as part of their annual compensation in for 2010. A total of 6,960 and 6,348 restricted unit awards were issued in February 2010 to the independent directors of EPGP and DEP GP, respectively, that immediately vested upon issuance.
(4) Aggregate grant date fair value of restricted unit awards denominated in our common units was $0.2 million based on a grant date market price of our common units of $25.26 per unit.

In the aggregate, unrecognized compensation cost of restricted unit awards was $53.2 million at September 30, 2010, of which our allocated share of the cost is currently estimated to be $5.2 million. We expect to recognize our share of the unrecognized compensation cost for these awards over a weighted-average period of 2.1 years.

Unit Option Awards

The 2010 Plan and EPCO's long-term incentive plans provide for the issuance of non-qualified incentive options. These option awards may be denominated in our common units or those of Enterprise Products Partners depending on the issuer of the award. When issued, the exercise price of each option award may be no less than the market price of the underlying security on the date of grant. In general, option awards have a vesting period of four years from the date of grant. If option awards are not exercised, these awards generally expire between five and ten years after the date of grant. There were no options granted under our 2010 Plan during the nine months ended September 30, 2010.

The fair value of each unit option is estimated on the date of grant using a Black-Scholes option pricing model, which incorporates various assumptions including expected life of the option, risk-free interest rates, expected distribution yield of the underlying security, and expected unit price volatility. Compensation expense is recognized based on the grant date fair value, net of an allowance for estimated forfeitures, over the vesting period.

The following table presents unit option activity under EPCO's plans for the period indicated. As of September 30, 2010, only Enterprise Products Partners has issued and outstanding unit option awards.

	Number of Units	Weighted-Average Strike Price (dollars/unit)	Weighted-Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value (1)
Unit options at December 31, 2009	3,825,920	$ 26.52		
Granted (2)	785,000	$ 32.26		
Exercised	(812,500)	$ 25.01		
Unit options at September 30, 2010	3,798,420	$ 28.03	3.9	$ 0.7
Options exercisable at September 30, 2010	45,000	$ 24.30	4.4	$ 0.7

(1) Aggregate intrinsic value reflects fully vested unit options at the date indicated.
(2) Aggregate grant date fair value of these unit options was $2.3 million based on the following assumptions: (i) a weighted-average grant date market price of Enterprise Products Partners' common units of $32.26 per unit; (ii) weighted-average expected life of options of 4.9 years; (iii) weighted-average risk-free interest rate of 2.5%; (iv) weighted-average expected distribution yield on Enterprise Products Partners' common units of 6.9%; and (v) weighted-average expected unit price volatility on Enterprise Products Partners' common units of 23.3%. An estimated forfeiture rate of 17% was applied to awards granted during 2010.

In the aggregate, unrecognized compensation cost of unit option awards was $8.5 million at September 30, 2010, of which our allocated share of the cost is currently estimated to be $0.6 million. We expect to recognize our share of the unrecognized compensation cost for these awards over a weighted-average period of 2.5 years.

Profits Interests Awards

As long-term incentive arrangements, EPCO granted its key employees who perform services on behalf of us, EPCO and other affiliated companies, "profits interests" in the Employee Partnerships. These partnerships were liquidated in August 2010. Prior to liquidation, the profits interests awards entitled each holder to participate in the expected long-term appreciation in value of the equity securities owned by each Employee Partnership. Each of the Employee Partnerships owned either units of Holdings or common units of Enterprise Products Partners or a combination of both. During the three months ended September 30, 2010, we recognized approximately $2.7 million of expense in connection with the liquidation of the Employee Partnerships. Of this expense amount, approxima tely $1.7 million was non-cash.

Note 4. Derivative Instruments, Hedging Activities and Fair Value Measurements

In the normal course of our business operations, we are exposed to certain risks, including changes in interest rates and commodity prices. In order to manage risks associated with certain anticipated future transactions, we use derivative instruments. Derivatives are instruments whose fair value is determined by changes in a specified benchmark such as interest rates or commodity prices. Fair value is generally defined as the amount at which a derivative instrument could be exchanged in a current transaction between willing parties, not in a forced sale. Typical derivative instruments include physical forward agreements, futures contracts, floating-to-fixed swaps, basis swaps and options contracts. Substantially all of our derivatives are used for non-trading activities.

We are required to recognize derivative instruments at fair value as either assets or liabilities on the balance sheet. While all derivatives are required to be reported at fair value on the balance sheet, changes in fair value of the derivative instruments are reported in different ways, depending on the nature and effectiveness of the hedging activities to which they relate. After meeting specified conditions, a qualified derivative may be specifically designated as a total or partial hedge of:

§ Changes in the fair value of a recognized asset or liability, or an unrecognized firm commitment - In a fair value hedge, gains and losses for both the derivative instrument and the hedged item are recognized in income during the period of change.

§ Variable cash flows of a forecasted transaction - In a cash flow hedge, the effective portion of the hedge is reported in other comprehensive income (loss) and is reclassified into earnings when the forecasted transaction affects earnings.

An effective hedge relationship is one in which the change in fair value of a derivative instrument can be expected to offset 80% to 125% of the changes in fair value of a hedged item at inception and throughout the life of the hedging relationship. The effective portion of a hedge relationship is the amount by which the derivative instrument exactly offsets the change in fair value of the hedged item during the reporting period. Conversely, ineffectiveness represents the change in the fair value of the derivative instrument that does not exactly offset the change in the fair value of the hedged item. Any ineffectiveness associated with a hedge relationship is recognized in earnings immediately. Ineffectiveness can be caused by, among other thi ngs, changes in the timing of forecasted transactions or a mismatch of terms between the derivative instrument and the hedged item.

A contract designated as a cash flow hedge of an anticipated transaction that is probable of not occurring is immediately recognized in earnings.

Certain of our derivative instruments do not qualify for hedge accounting treatment; therefore, they are accounted for using mark-to-market accounting.

Interest Rate Derivative Instruments

We utilized interest rate swaps to manage our exposure to changes in the interest rates charged on borrowings under our $300.0 million unsecured revolving credit facility (the "Revolving Credit Facility") from September 2007 through September 2010. This strategy was a component in controlling our cost of capital associated with such borrowings.

Interest rate swaps exchange the stated interest rate paid on a notional amount of debt for a fixed or floating interest rate stipulated in the derivative instrument. Our interest rate swaps resulted in an increase in interest expense of $1.8 million for each of the three months ended September 30, 2010 and 2009 and increases of $5.6 million and $4.7 million, respectively, for the nine months ended September 30, 2010 and 2009. Our interest rate swaps expired in September 2010.

Commodity Derivative Instruments

The price of natural gas is subject to fluctuations in response to changes in supply and demand, market conditions and a variety of additional factors that are beyond our control. In order to manage the price risk associated with certain exposures, we enter into commodity derivative instruments such as physical forward agreements, futures contracts, fixed-for-float swaps and basis swaps.

The following table summarizes our commodity derivative instruments outstanding at September 30, 2010:

Derivative Purpose	Volume (1) Current	Volume (1) Long-Term	Accounting Treatment
Derivatives designated as hedging instruments:			
Acadian Gas:			
Forecasted sales of natural gas	1.0 Bcf	n/a	Cash flow hedge
Derivatives not designated as hedging instruments:			
Acadian Gas:			
Natural gas risk management activities (2)	1.0 Bcf	n/a	Mark-to-market

(1) Volume for derivatives designated as hedging instruments reflects the total amount of volumes hedged whereas volume for derivatives not designated as hedging instruments reflects the absolute value of derivative notional volumes.
(2) Reflects the use of derivative instruments to manage risks associated with natural gas transportation and storage assets.

Our hedging strategy is intended to reduce the variability of future earnings and cash flows resulting from changes in natural gas prices. We enter into a limited number of forward transactions that effectively fix the price of natural gas for certain customers and hedge the resulting exposure with derivative instruments. We may also enter into a small number of cash flow hedges in connection with our purchases of natural gas held-for-sale to third parties.

Our general partner monitors the hedging strategies associated with these physical and financial risks, approves specific activities subject to the policy (including authorized products, instruments and markets) and establishes specific guidelines and procedures for implementing and ensuring compliance with the policy.

Credit-Risk Related Contingent Features in Derivative Instruments

Commodity derivative instruments can include provisions related to minimum credit ratings and/or adequate assurance clauses. The potential for derivatives with contingent features to enter a net liability position may change in the future as commodity positions and prices fluctuate.

Tabular Presentation of Fair Value Amounts, and Gains and Losses on Derivative Instruments and Related Hedged Items

The following table provides a balance sheet overview of our derivative assets and liabilities at the dates indicated:

	Asset Derivatives				Liability Derivatives			
	September 30, 2010		December 31, 2009		September 30, 2010		December 31, 2009	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Derivatives designated as hedging instruments:								
Interest rate derivatives	Other current assets	$ --	Other current assets	$ --	Other current liabilities	$ --	Other current liabilities	$ 5.5
Derivatives not designated as hedging instruments:								
Commodity derivatives	Other current assets	$ 0.4	Other current assets	$ 0.1	Other current liabilities	$ 0.4	Other current liabilities	$ 0.1

The following table presents the effect of our derivative instruments designated as cash flow hedges on our Unaudited Condensed Statements of Consolidated Comprehensive Income and Consolidated Operations for the periods indicated:

Derivatives in Cash Flow Hedging Relationships	Change in Value Recognized in Other Comprehensive Income on Derivative (Effective Portion)			
	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2010	2009	2010	2009
Interest rate derivatives	$ (0.1)	$ (1.1)	$ (0.2)	$ (0.9)
Commodity derivatives	--	--	(0.1)	--
Total	$ (0.1)	$ (1.1)	$ (0.3)	$ (0.9)

Derivatives in Cash Flow Hedging Relationships	Location	Loss Reclassified from Accumulated Other Comprehensive Income/Loss to Income (Effective Portion)			
		For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
		2010	2009	2010	2009
Interest rate derivatives	Interest expense	$ (1.8)	$ (1.8)	$ (5.6)	$ (4.7)

Derivatives in Cash Flow Hedging Relationships	Location	Gain (Loss) Recognized in Income on Ineffective Portion of Derivative			
		For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
		2010	2009	2010	2009
Interest rate derivatives	Interest expense	$ --	$ *	$ *	$ *

* Amount is negligible.

Over the next twelve months, we expect to reclassify $0.1 million of losses attributable to our commodity derivative instruments from accumulated other comprehensive loss to earnings as a decrease to revenues.

The following table presents the effect of our derivative instruments not designated as hedging instruments on our Unaudited Condensed Statements of Consolidated Operations for the periods indicated:

Derivatives Not Designated as Hedging Instruments	Location	Gain/(Loss) Recognized in Income on Derivative			
		For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
		2010	2009	2010	2009
Commodity derivatives	Revenue	$ (0.1)	$ (0.2)	$ (0.4)	$ (0.4)

Fair Value Measurements

Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at a specified measurement date. Our fair value estimates are based on either (i) actual market data or (ii) assumptions that other market participants would use in pricing an asset or liability, including estimates of risk. Recognized valuation techniques employ inputs such as product prices, operating costs, discount factors and business growth rates. These inputs may be either readily observable, corroborated by market data or generally unobservable. In developing our estimates of fair value, we endeavor to utilize the best information available and apply market-based data to the extent possible. Accordingly, we utilize valuation techniques (such as the market approach) that maximize the use of observable inputs and minimize the use of unobservable inputs.

A three-tier hierarchy has been established that classifies fair value amounts recognized or disclosed in the financial statements based on the observability of inputs used to estimate such fair values.

The hierarchy considers fair value amounts based on observable inputs (Levels 1 and 2) to be more reliable and predictable than those based primarily on unobservable inputs (Level 3). At each balance sheet reporting date, we categorize our financial assets and liabilities using this hierarchy.

The characteristics of fair value amounts classified within each level of the hierarchy are described as follows:

§ Level 1 fair values are based on quoted prices, which are available in active markets for identical assets or liabilities as of the measurement date. Active markets are defined as those in which transactions for identical assets or liabilities occur with sufficient frequency so as to provide pricing information on an ongoing basis (e.g., the New York Mercantile Exchange). Our Level 1 fair values primarily consist of financial assets and liabilities such as exchange-traded commodity derivative instruments.

§ Level 2 fair values are based on pricing inputs other than quoted prices in active markets (as reflected in Level 1 fair values) and are either directly or indirectly observable as of the measurement date. Level 2 fair values include instruments that are valued using financial models or other appropriate valuation methodologies. Such financial models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, the time value of money, volatility factors, current market and contractual prices for the underlying instruments and other relevant economic measures. Substantially all of these assumptions (i) are observable in the marketplace throughout the full term of the instrument, (ii) can be derived from observable data or (iii) are validated by inputs other t han quoted prices (e.g., interest rate and yield curves at commonly quoted intervals). Our commodity derivative instruments can consist of instruments such as forwards, swaps and other instruments transacted on an exchange or over-the-counter. The fair values of these derivatives are based on observable price quotes for similar products and locations.

§ Level 3 fair values are based on unobservable inputs. Unobservable inputs are used to measure fair value to the extent that observable inputs are not available, thereby allowing for situations in which there is little, if any, market activity for the asset or liability at the measurement date. Unobservable inputs reflect our ideas about the assumptions that market participants would use in pricing an asset or liability (including assumptions about risk). Unobservable inputs are based on the best information available to us in the circumstances, which might include our internally developed data. Level 3 inputs are typically used in connection with internally developed valuation methodologies where we make our best estimate of an instrument’s fair value. Level 3 generally includes specialized or unique financial instruments that are tailored to meet a customer’s specific needs. At September 30, 2010, we did not have any Level 3 financial assets or liabilities.

The following table sets forth, by level within the fair value hierarchy, our financial assets and liabilities at September 30, 2010. These financial assets and liabilities are measured each quarterly reporting period and are classified based on the lowest level of input that is significant to their respective fair value measurements. Our assessment of the relative significance of such inputs requires judgment. There were no significant transfers between Levels 1, 2 or 3 during the nine months ended September 30, 2010.

	At September 30, 2010			
	Level 1	Level 2	Level 3	Total
Financial assets:				
Commodity derivatives	$ --	$ 0.4	$ --	$ 0.4
Financial liabilities:				
Commodity derivatives	$ 0.4	$ --	$ --	$ 0.4

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Nonfinancial Assets and Liabilities

During the nine months ended September 30, 2010, we reduced certain assets recorded as property, plant and equipment to fair value based on the present value of expected future cash flows (Level 3), resulting in nonrecurring fair value charges totaling $1.5 million.

Note 5. Inventories

Our inventory amounts were as follows at the dates indicated:

	September 30, 2010	December 31, 2009
Working inventory (1)	$ 4.2	$ 4.4
Forward sales inventory (2)	6.0	6.1
Total inventory	$ 10.2	$ 10.5

(1) Working inventory is comprised of inventories of natural gas that are used in the provision for services.
(2) Forward sales inventory consists of identified natural gas volumes dedicated to the fulfillment of forward sales contracts.

Working inventory includes natural gas volumes held for operational system balancing on the Texas Intrastate System. These natural gas inventories fluctuate as a result of imbalances with shippers and are valued based on a twelve-month rolling average of posted industry prices. When such volumes are delivered out of inventory, the average cost of these volumes is charged against our accrued gas imbalance payables. At September 30, 2010 and December 31, 2009, the value of natural gas held in inventory for operational system balancing was $1.8 million and $2.8 million, respectively.

The following table presents our cost of sales and lower of cost or market ("LCM") adjustments for the periods indicated:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2010	2009	2010	2009
Cost of sales (1)	$ 149.2	$ 120.7	$ 448.9	$ 368.0
LCM adjustments	*	*	0.1	*

(1) Cost of sales is a component of "Operating costs and expenses" as presented on our Unaudited Condensed Statements of Consolidated Operations. Period-to-period fluctuations in these amounts are primarily due to changes in natural gas prices.
* We recognized nominal LCM adjustments during the periods presented.

Note 6. Property, Plant and Equipment

Our property, plant and equipment values and related accumulated depreciation balances were as follows at the dates indicated:

	Estimated Useful Life in Years	September 30, 2010	December 31, 2009
Plant and pipelines (1)	3-45 (4)	$ 5,049.1	$ 4,767.0
Underground storage wells and related assets (2)	5-35 (5)	446.7	432.5
Transportation equipment (3)	3-10	12.6	11.3
Land		33.9	27.8
Construction in progress		577.0	233.6
Total		6,119.3	5,472.2
Less: accumulated depreciation		1,047.9	922.6
Property, plant and equipment, net		$ 5,071.4	$ 4,549.6

(1) Plants and pipelines include natural gas, NGL and petrochemical pipelines, NGL fractionation plants, office furniture and equipment, buildings and related assets.
(2) Underground storage facilities include underground product storage caverns and related assets such as pipes and compressors.
(3) Transportation equipment includes vehicles and similar assets used in our operations.
(4) In general, the estimated useful lives of major components of this category are as follows: pipelines, 18-45 years (with some equipment at 5 years); office furniture and equipment, 3-20 years; buildings 20-35 years; and fractionation facilities, 28 years.
(5) In general, the estimated useful life of this category is 20-35 years (with some components at 5 years).

The following table summarizes our depreciation expense and capitalized interest amounts for the periods indicated:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2010	2009	2010	2009
Depreciation expense (1)	$ 46.0	$ 44.9	$ 139.9	$ 130.6
Capitalized interest (2)	1.2	*	1.5	0.2

(1) Depreciation expense is a component of "Costs and expenses" as presented on our Unaudited Condensed Statements of Consolidated Operations.
(2) Capitalized interest increases the carrying value of the associated asset and reduces interest expense during the period it is recorded.
* Amount is immaterial

Operating expense for the three and nine months ended September 30, 2010 includes a $9.1 million non-cash charge resulting from the disposition of a pipeline segment in South Texas that was in natural gas gathering service.

Haynesville Extension

Our consolidated construction in progress amounts at September 30, 2010 include $336 million of capital expenditures related to the Haynesville Extension project. Based on the current spending forecast for this project, we expect that consolidated capital spending (on a 100% basis, including capitalized interest) for the Haynesville Extension will approximate $200 million for the remainder of 2010 and $1.56 billion for the entire project through completion.

Our 66% share of the total expected cost of the Haynesville Extension is estimated at $1.03 billion. We expect that our 66% share of the capital spending for this project for the remainder of 2010 will approximate $130 million. For information regarding the funding of the Haynesville Extension, see "Significant Relationships and Agreements with EPO – Amended Acadian LLC Agreement" under Note 13.

Asset Retirement Obligations

We record asset retirement obligations ("AROs") related to legal requirements to perform retirement activities as specified in contractual arrangements and/or governmental regulations. In general, our AROs primarily result from (i) right-of-way agreements associated with our pipeline operations, (ii) leases of plant sites and (iii) regulatory requirements triggered by the abandonment or retirement of certain facilities. In addition, our AROs may result from the renovation or demolition of certain assets containing hazardous substances such as asbestos.

The following table presents information regarding our AROs since December 31, 2009:

ARO liability balance, December 31, 2009	$	10.4
Liabilities settled during the period		(5.3)
Accretion expense		0.5
Revisions in estimated cash flows		1.9
ARO liability balance, September 30, 2010	$	7.5

Property, plant and equipment at September 30, 2010 and December 31, 2009 includes $3.4 million and $5.5 million, respectively, of asset retirement costs capitalized as an increase in the associated long-lived assets. The following table presents forecasted accretion expense associated with our AROs for the years presented:

2010 (1)	**2011**	**2012**	**2013**	**2014**
$ 0.1	$ 0.6	$ 0.6	$ 0.7	$ 0.8

(1) Amount represents the estimate for the remainder of 2010.

Note 7. Investment in Evangeline

Acadian Gas, through a wholly owned subsidiary, owns a collective 49.51% equity interest in Evangeline, which consists of a 45% direct ownership interest in EGP and a 45.05% direct interest in EGC. EGC also owns a 10% direct interest in EGP. Third parties own the remaining equity interests in EGP and EGC. Acadian Gas does not have a controlling interest in the Evangeline entities, but does exercise significant influence over Evangeline's operating policies. Acadian Gas accounts for its investment in Evangeline using the equity method. Our investment in Evangeline is classified within our Natural Gas Pipelines & Services business segment.

Evangeline owns a 27-mile natural gas pipeline system extending from Taft, Louisiana to Westwego, Louisiana that connects three electric generation stations owned by Entergy Louisiana ("Entergy"). Evangeline's most significant contract is a 21-year natural gas sales agreement with Entergy. Evangeline is obligated to make available for sale and deliver to Entergy certain specified minimum contract quantities of natural gas on an hourly, daily, monthly and annual basis. The sales contract provides for minimum annual quantities of 36.8 billion British thermal units ("BBtus"), until the contract expires on January 1, 2013.

In connection with the Entergy sales contract, Evangeline has entered into a natural gas purchase contract with a subsidiary of Acadian Gas that contains annual purchase provisions. The pricing terms of the sales agreement with Entergy and Evangeline's purchase agreement with Acadian Gas are based on a weighted-average cost of natural gas each month (subject to certain market index price ceilings and incentive margins) plus a predetermined margin, creating an essentially fixed monthly net sales margin.

In 1991, Evangeline entered into an agreement with Entergy whereby Entergy was granted the right to acquire Evangeline's pipeline system for a nominal price, plus the assumption of all of Evangeline's obligations under the natural gas sales contract. The option period began on July 1, 2010 and terminates on December 31, 2012. While Entergy has expressed an interest in exercising this purchase option, we cannot ascertain when, or if, it will be exercised. This uncertainty results from various factors,

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including decisions by Entergy's management and regulatory approvals that may be required for Entergy to acquire Evangeline's assets.

We have received no distributions from Evangeline since we acquired our interest in Evangeline in April 2001. The trust indenture governing Evangeline's senior notes places restrictions on the payment of distributions to Evangeline's partners. Evangeline is permitted to pay distributions if, after giving effect to the distribution, no default or event of default has occurred and is continuing, funds held in its restricted cash account equals or exceeds its debt service requirement and the holders of the senior notes are cash secured. Our share of undistributed earnings of Evangeline totaled approximately $4.2 million at September 30, 2010. See Note 9 for a description of Evangeline's outstanding debt obligations.

The following table presents unaudited summarized income statement (on a 100% basis) information of Evangeline for the periods indicated:

	Summarized Income Statement Information for the Three Months Ended					
	September 30, 2010			September 30, 2009		
	Revenues	Operating Income	Net Income	Revenues	Operating Income	Net Income
Natural Gas Pipelines & Services	$ 61.1	$ 0.7	$ 0.5	$ 52.3	$ 1.1	$ 0.9

	Summarized Income Statement Information for the Nine Months Ended					
	September 30, 2010			September 30, 2009		
	Revenues	Operating Income	Net Income	Revenues	Operating Income	Net Income
Natural Gas Pipelines & Services	$ 151.9	$ 1.4	$ 1.0	$ 131.0	$ 2.8	$ 1.9

Note 8. Intangible Assets and Goodwill

Identifiable Intangible Assets

The following table summarizes our intangible asset balances by segment at the dates indicated:

	At September 30, 2010			At December 31, 2009		
	Gross Value	Accum. Amort.	Carrying Value	Gross Value	Accum. Amort.	Carrying Value
NGL Pipelines & Services:						
Customer relationship intangibles	$ 24.6	$ (10.4)	$ 14.2	$ 24.6	$ (8.9)	$ 15.7
Contract-based intangibles	42.3	(28.4)	13.9	40.8	(24.7)	16.1
Natural Gas Pipelines & Services:						
Customer relationship intangibles	21.0	(10.0)	11.0	21.0	(9.0)	12.0
Total all segments	$ 87.9	$ (48.8)	$ 39.1	$ 86.4	$ (42.6)	$ 43.8

The following table presents amortization expense related to our intangible assets for the periods indicated:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2010	2009	2010	2009
NGL Pipelines & Services	$ 1.7	$ 1.7	$ 5.2	$ 5.3
Natural Gas Pipelines & Services	0.3	0.4	1.0	1.1
Total all segments	$ 2.0	$ 2.1	$ 6.2	$ 6.4

The following table presents our forecast of amortization expense associated with existing intangible assets for the years presented:

	For the Year Ended December 31,				
	2010 (1)	2011	2012	2013	2014
NGL Pipelines & Services	$ 1.7	$ 6.5	$ 3.0	$ 1.7	$ 1.5
Natural Gas Pipelines & Services	0.3	1.2	1.1	1.0	0.9
Total segments	$ 2.0	$ 7.7	$ 4.1	$ 2.7	$ 2.4

(1) Amounts represent the estimate for the fourth quarter of 2010.

In general, our intangible assets fall within two categories: customer relationships and contract-based intangible assets. The values assigned to such intangible assets are amortized to earnings using either (i) a straight-line approach or (ii) other methods that closely resemble the pattern in which the economic benefits of associated resource bases are estimated to be consumed or otherwise used.

Customer relationship intangible assets. Customer relationship intangible assets represent the estimated economic value assigned to certain relationships acquired in connection with our DEP I and DEP II drop down transactions whereby (i) we acquired information about or access to customers and (ii) the customers now have the ability to make direct contact with us. Customer relationships may arise from contractual arrangements (such as supplier contracts and service contracts) and through means other than contracts, such as through regular contact by sales or service representatives. At September 30, 2010, the carrying value of our customer relationship intangible assets was $25.2 million.

Contract-based intangible assets. Contract-based intangible assets represent specific commercial rights arising from discrete contractual agreements which we acquired in connection with our DEP I and DEP II drop down transactions. At September 30, 2010, the carrying value of our contract-based intangible assets was $13.9 million.

Goodwill

Goodwill represents the excess of the purchase price of an acquired business over the amounts assigned to assets acquired and liabilities assumed in the transaction. Goodwill is not amortized; however, it is subject to annual impairment testing at the beginning of each fiscal year. The carrying value of our goodwill does not include any accumulated impairment charges. We had $4.9 million of goodwill associated with the DEP II Midstream Businesses recorded at September 30, 2010 and December 31, 2009.

Note 9. Debt Obligations

On October 25, 2010, we entered into new long-term variable rate senior unsecured credit facilities having an aggregate borrowing capacity of $1.25 billion. The new credit facilities mature in October 2013 and consist of: (i) an $850.0 million multi-year revolving credit facility (the “DEP Multi-Year Revolving Credit Facility”) and (ii) a $400.0 million term loan facility (the “$400 Million Term Loan Facility”). At closing, we borrowed the full amount available under the $400 Million Term Loan Facility to repay amounts outstanding under our Revolving Credit Facility and the Loan Agreement with EPO. Upon repayment, our existing Revolving Credit Facility and the Loan Agreement with EPO were terminated. Our existing $282.3 million term loan agreement (the “Term Loa n Agreement”) remains in place and is scheduled to mature in December 2011.

We entered into these new credit agreements primarily to address our share of the funding requirements for the Haynesville Extension project under the Amended Acadian LLC Agreement (see Note 13). Variable interest rates charged under the new credit facilities are based on the London InterBank Offered Rate (or “LIBOR”) or a base rate, both as defined in the agreement.

Our consolidated debt obligations consisted of the following at the dates indicated:

	At September 30, 2010	At December 31, 2009
Revolving Credit Facility, variable rate, due February 2011 (1)	$ 247.5	$ 175.0
Term Loan Agreement, variable rate, due December 2011 (2)	282.3	282.3
Loan Agreement with EPO, variable rate, due December 2010 (1,3)	125.0	--
Total long-term debt	$ 654.8	$ 457.3

(1) Amount outstanding at September 30, 2010 is excluded from current liabilities after taking into account repayments made on October 25, 2010 using long-term borrowing capacity under our new $850.0 million DEP Multi-Year Revolving Credit Facility.
(2) Refers to our April 2008 $300.0 million Term Loan Agreement, the borrowing capacity of which was subsequently reduced to $282.3 million due to the bankruptcy of one of the lenders.
(3) Refers to our $200.0 million revolving Loan Agreement with EPO.

Loan Agreement with EPO

On June 1, 2010, we entered into a $200 million revolving loan agreement with EPO (the “Loan Agreement with EPO”). Our borrowings under this revolving loan agreement were primarily used to fund our share of project costs for the Haynesville Extension. The Loan Agreement with EPO was terminated on October 25, 2010 and amounts due thereunder were repaid using borrowings under our new $400 Million Term Loan Facility. For the three and nine months ended September 30, 2010, we paid EPO fees of $0.1 million and $0.2 million, respectively, in connection with this loan agreement. Interest accrued on outstanding borrowings at a variable rate equal to one-month LIBOR plus 2.50%. We recognized interest expense of $0.5 million for the three and nine months ended September 30, 2010 .

Covenants

We were in compliance with the financial covenants of our consolidated debt agreements at September 30, 2010.

Information Regarding Variable Interest Rates Paid

The following table presents the range of interest rates and weighted-average interest rates paid on our consolidated variable-rate debt obligations during the nine months ended September 30, 2010.

	Range of Interest Rates Paid	Weighted-average Interest Rates Paid
Revolving Credit Facility	0.80% to 1.19%	0.94%
Term Loan Agreement	0.93% to 1.09%	1.00%
Loan Agreement with EPO	2.76% to 2.82%	2.78%

Evangeline Joint Venture Debt Obligation

At September 30, 2010, Evangeline’s debt consisted of $3.2 million of 9.9% fixed rate senior notes due December 2010, which is fully cash secured by Evangeline, and a $3.2 million subordinated note payable due on the 90th day following the final payment of the senior notes. In July 2010, Evangeline made a $7.0 million payment, of which $2.7 million was applied to accrued interest and $4.3 million was applied to the subordinated note payable. Evangeline was in compliance with its debt covenants at September 30, 2010. There have been no changes in the terms of Evangeline’s debt agreements since those reported in our 2009 Form 10-K/A. At September 30, 2010, the amount of accrued but unpaid interest on the subordinated note payable was negligible. At December 31, 2009, the amount of accrued but unpaid interest was approximately $10.2 million.

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Note 10. Equity and Distributions

Our common units represent limited partner interests, which give holders thereof the right to participate in cash distributions and to exercise the other rights or privileges available to them under our Amended and Restated Agreement of Limited Partnership (as amended from time to time, the "Partnership Agreement").

In accordance with the Partnership Agreement, capital accounts are maintained for our general partner and our limited partners. The capital account provisions of the Partnership Agreement incorporate principles established for U.S. federal income tax purposes and are not comparable to the GAAP-based equity amounts presented in our consolidated financial statements. Earnings and cash distributions are allocated to holders of our common units in accordance with their respective ownership interests.

Class B Units

In December 2008, we issued 37,333,887 Class B units, which were used along with proceeds borrowed under the Term Loan Agreement to acquire the DEP II Midstream Businesses. In February 2009, the Class B units were converted on a one-to-one basis into common units and received a pro-rated cash distribution of $0.1115 per unit for the distribution that Duncan Energy Partners paid with respect to the fourth quarter of 2008, which represented the regular quarterly distribution pro-rated for the 24-day period from December 8, 2008, the closing date of the DEP II drop down transaction, to December 31, 2008.

Registration Statements and Equity Offerings

We have a universal shelf registration statement on file with the SEC that allows us to issue up to an aggregate $1 billion in debt and equity securities for general partnership purposes. After taking into account previous issuances of securities under this registration statement, we can issue approximately $856.4 million of additional securities under this registration statement in the future.

In June 2009, we completed an offering of 8,000,000 common units under this universal shelf registration statement that generated net cash proceeds of approximately $122.9 million after underwriting discounts and other expenses. In July 2009, the underwriters to this offering exercised their option to purchase an additional 943,400 common units, which generated approximately $14.5 million of additional net proceeds. The total net cash proceeds from this offering, including the overallotment amount, were used to repurchase an equal number of our common units beneficially owned by EPO – 8,000,000 common units were repurchased in June 2009 and 943,400 common units were repurchased in July 2009. The repurchased common units were subsequently cancelled.< /font>

We filed a registration statement with the SEC authorizing the issuance of up to an aggregate 2,000,000 common units in connection with a distribution reinvestment plan ("DRIP"). The DRIP gives unitholders of record and beneficial owners of our common units the ability to increase the number of our common units they own through voluntarily reinvesting their quarterly cash distributions into the purchase of additional common units. Plan participants may purchase our common units at a discount ranging from 0% to 5% (currently set at 5%), which will be set from time to time by us. We issued 31,762 common units under the DRIP through September 30, 2010.

In February 2010, we filed a registration statement with the SEC authorizing the issuance of up to an aggregate 1,000,000 common units in connection with an employee unit purchase plan ("EUPP") and a long-term incentive plan. These plans became effective on February 11, 2010.

The following table reflects the number of common units issued and the net cash proceeds received from our common unit offerings during the nine months ended September 30, 2010:

	Net Cash Proceeds from Issuance of Common Units			
	Number of Common Units Issued	Contributed by Limited Partners	Contributed by General Partner	Total Net Cash Proceeds
February DRIP	10,385	$ 0.2	$ *	$ 0.2
May DRIP	11,521	0.3	*	0.3
May EUPP	11,017	0.3	*	0.3
August DRIP	9,856	0.2	*	0.2
August EUPP	6,962	0.2	*	0.2
Total 2010	49,741	$ 1.2	$ *	$ 1.2

* Amount is negligible.

Net cash proceeds received from our common unit offerings were used for general partnership purposes.

Summary of Changes in Outstanding Units

The following table summarizes changes in the number of our limited partner units outstanding for the since December 31, 2009:

	Common Units	Restricted Common Units
Balance, December 31, 2009	57,676,987	--
Common units issued in connection with DRIP and EUPP	49,741	--
Restricted units issued to independent directors under our 2010 Plan	--	6,348
Conversion of restricted units to common units	6,348	(6,348)
Balance, September 30, 2010	57,733,076	--

Distributions to Partners

Our partnership agreement requires us to distribute all of our available cash (as defined in our Partnership Agreement) to our partners on a quarterly basis. Such distributions are not cumulative. In addition, we do not have a legal obligation to pay distributions at our initial distribution rate or at any other rate. Our general partner has no incentive distribution rights. The following table presents our declared quarterly cash distribution rates per common unit since the first quarter of 2009 and the related record and distribution payment dates. The quarterly cash distribution rates per common unit correspond to the fiscal quarters indicated. Actual cash distributions are paid within 45 days after the end of such fisc al quarter.

	Cash Distribution History		
	Per Unit	Record Date	Payment Date
2009			
1st Quarter	0.4300	April 30, 2009	May 8, 2009
2nd Quarter	0.4350	July 31, 2009	August 7, 2009
3rd Quarter	0.4400	October 30, 2009	November 5, 2009
4th Quarter	0.4450	January 29, 2010	February 5, 2010
2010			
1st Quarter	0.4475	April 30, 2010	May 6, 2010
2nd Quarter	0.4500	July 30, 2010	August 6, 2010
3rd Quarter	0.4525	October 29, 2010	November 8, 2010

Accumulated Other Comprehensive Income (Loss)

Our accumulated other comprehensive income (loss) balance reflects a loss of $5.4 million at December 31, 2009, which related primarily to our interest rate derivative instruments. Our balance at September 30, 2010 reflects a loss of $0.1 million related to our commodity derivative instruments.

Note 11. Noncontrolling Interest

We account for EPO's retained ownership interests in each of the DEP I and DEP II Midstream Businesses as noncontrolling interest. Under this method of presentation, all revenues and expenses of these businesses are included in our consolidated net income and EPO's share (as Parent) of the earnings of these businesses is deducted from consolidated net income to derive net income attributable to Duncan Energy Partners L.P. EPO's ownership of the net assets of the DEP I and DEP II Midstream Businesses is presented as noncontrolling interest in subsidiaries (a component of equity) on our Unaudited Condensed Consolidated Balance Sheets. See Note 1 for a general description of the DEP I and DEP II Midstream Businesses.

DEP I Midstream Businesses – Parent

The following table presents our calculation of "Net income (loss) attributable to noncontrolling interest – DEP I Midstream Businesses – Parent" for the periods indicated:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2010	2009	2010	2009
Total net income of DEP I Midstream Businesses, after special allocations	$ 18.5	$ 19.0	$ 51.7	$ 49.0
Multiplied by Parent 34% interest in net income	x 34%	x 34%	x 34%	x 34%
Parent 34% interest in net income, after special allocations	6.4	6.4	17.6	16.7
Add (deduct) operational measurement gains (losses) allocated to Parent	2.6	0.8	7.0	(1.8)
Less depreciation expense related to capital projects funded entirely by and allocated to Parent	(1.6)	(1.5)	(4.7)	(4.6)
Net income attributable to noncontrolling interest – DEP I Midstream Businesses – Parent	$ 7.4	$ 5.7	$ 19.9	$ 10.3

The DEP I Midstream Businesses allocate their net income (or loss) to EPO and us based on our respective sharing ratios, which are currently 34% for EPO and 66% for us. In deriving the net income (or loss) of Mont Belvieu Caverns to be allocated between EPO and us, certain special allocations are required: (i) EPO is allocated all operational measurement gains and losses and (ii) EPO is allocated 100% of the depreciation expense related to capital projects that it has fully funded.

The following table provides a reconciliation of the amount presented as "Noncontrolling interest in subsidiaries – DEP I Midstream Businesses – Parent," on our Unaudited Condensed Consolidated Balance Sheets at September 30, 2010:

December 31, 2009 balance	$ 487.3
Net income attributable to noncontrolling interest – DEP I Midstream Businesses – Parent	19.9
Contributions made by EPO to Mont Belvieu Caverns in connection with the Caverns LLC Agreement	17.4
Contributions made by EPO to Acadian Gas in connection with the Amended Acadian LLC Agreement	85.2
Other contributions made by EPO to the DEP I Midstream Businesses	25.3
Distributions paid to EPO by the DEP I Midstream Businesses	(21.0)
September 30, 2010 balance	$ 614.1

Cash distributions by the DEP I Midstream Businesses to EPO and us are paid in accordance with each owner's respective sharing ratio. Likewise, cash contributions by EPO and us to the DEP I Midstream Businesses are made in accordance with the same sharing ratios; however, special funding arrangements exist with respect to certain capital projects under the terms of the limited liability company agreement of Mont Belvieu Caverns (the "Caverns LLC Agreement") and an Omnibus Agreement. No capital spending for the DEP I Midstream Businesses was funded by EPO under the Omnibus Agreement during 2010.

Caverns LLC Agreement. EPO made cash contributions of $17.4 million and $14.1 million under the Caverns LLC Agreement during the nine months ended September 30, 2010 and 2009, respectively, to fund 100% of certain storage-related infrastructure projects sponsored by and for the benefit of EPO's NGL marketing activities. Duncan Energy Partners elected to not participate in these projects. Although Mont Belvieu Caverns owns the constructed assets, it is not expected to benefit economically from these specific capital improvements. As a result, EPO is not expected to receive an increased allocation of earnings or cash flows from Mont Belvieu Caverns as a result of these contributed capital expenditures. EPO will, however, be allocated the depreciation expense attributable to these projects. EPO's NGL marketing activities receive economic benefit directly from these expansion projects via increased marketing revenues. Additional contributions of approximately $9.9 million are expected from EPO to fund these specific projects for the remainder of 2010.

Operational measurement gains and losses are created when product is moved between storage wells and are attributable to pipeline and well connection measurement variances. The Caverns LLC Agreement allocates to EPO any items of income or loss relating to net operational measurement gains and losses, including amounts that Mont Belvieu Caverns may retain for handling losses. As such, EPO is required to contribute cash to Mont Belvieu Caverns for net operational measurement losses and is entitled to receive cash distributions from Mont Belvieu Caverns for net operational measurement gains. Operational measurement gains and losses are reflected in our consolidated operating costs and expenses and gross operating margin amounts; however, these gains and losses do not impact net income attributable to Duncan Ene rgy Partners since they are allocated to EPO through noncontrolling interest. In addition, operational measurement gains or losses do not have a significant impact on us with respect to the timing of our net cash flows provided by operating activities. Accordingly, we have not established a reserve for operational measurement losses on our balance sheet.

Amended Acadian LLC Agreement. On June 1, 2010, we entered into a second amended and restated limited liability company agreement for Acadian Gas (the "Amended Acadian LLC Agreement") with EPO. As part of this agreement, we and EPO agreed to fund the construction of the Haynesville Extension in accordance with our respective sharing ratios in Acadian Gas (i.e., 66% for us and 34% for EPO). EPO made cash contributions of $85.2 million to Acadian Gas under the Amended Acadian LLC Agreement in connection with the Haynesville Extension project during the nine months ended September 30, 2010. For additional information regarding the Amended Acadian LLC Agreement, see "Significant Relationships and Agreements with EPO – Amended Acadian LLC Agreement" under Note 13.

For additional information regarding our agreements with EPO in connection with the DEP I drop down transaction, see Note 13.

DEP II Midstream Businesses – Parent

At the time of the DEP II drop down transaction, the total estimated fair value of the DEP II Midstream Businesses was approximately $3.2 billion. The total value of the consideration we provided to EPO in the DEP II drop down transaction was $730.0 million and represented, at the time of the transaction, the acquisition of controlling voting interests along with an initial 22.6% of the equity of the DEP II Midstream Businesses. EPO retained the remaining 77.4% of equity. The 22.6% and 77.4% amounts are referred to as the "Percentage Interests," and represent each owner's initial relative economic investment in the DEP II Midstream Businesses at December 8, 2008.

To the extent that the DEP II Midstream Businesses collectively generate cash sufficient to pay distributions to EPO and us, such cash will be distributed first to us (the "Tier I distribution," based on our $730.0 million aggregate investment) and then to EPO (the "Tier II distribution"), in amounts sufficient to generate an annualized return to both owners based on their respective investments. Distributions in excess of these amounts (the "Tier III distributions") will be distributed 98% to EPO and 2% to us.

The annualized return rate from December 8, 2008 through December 31, 2009 was 11.85%, and was determined by EPO and us based on our estimated weighted-average cost of capital at December 8, 2008, plus 1.0%. The annualized return rate increases by 2.0% on January 1 of each year. As a result, the annualized return rate for fiscal 2010 is 12.087%. If we participate in an expansion capital project involving the DEP II Midstream Businesses, we may request an incremental adjustment to the then-applicable annualized return rate to reflect our weighted-average cost of capital associated with such contribution.

The annualized return rate is applied to each party's aggregate investment (or "Distribution Base") in the DEP II Midstream Businesses. To the extent that we and/or EPO make capital contributions to fund expansion capital projects involving the DEP II Midstream Businesses, the Distribution Base of the contributing member will be increased by that member's capital contribution at the time such contribution is made. At December 8, 2008 and September 30, 2010, our Distribution Base was $730.0 million. EPO's Distribution Base was $452.1 million, $817.9 million and $1.05 billion at December 8, 2008, December 31, 2009 and September 30, 2010, respectively. The increase in EPO's Distribution Base is the result of its funding 100% of the expansion capital projects of the DEP II Midstream Businesses since December 8, 2008. For the nine months ended September 30, 2010, EPO funded $228.3 million of expansion capital spending for the DEP II Midstream Businesses. This spending primarily relates to natural gas pipeline projects in the Barnett Shale (e.g., completion of the Trinity River Lateral in July 2010) and ongoing expansions of our pipeline network in the Eagle Ford Shale region. We have not yet participated in the expansion capital project spending of the DEP II Midstream Businesses, although we may elect to invest in existing or future expansion projects at a later date.

Net income (or loss) of the DEP II Midstream Businesses is first allocated to us and EPO based on each entity's Percentage Interest of 22.6% and 77.4%, respectively, and then in a manner that in part follows the cash distributions paid by (or contributions made to) each of the DEP II Midstream Business. Under our income sharing arrangement with EPO, we are allocated additional income (in excess of our Percentage Interest) to the extent that the cash distributions we receive (or contributions made) exceed the amount we would have been entitled to receive (or required to fund) based solely on our Percentage Interest. This additional earnings allocation to us reduces the amount of income allocated to EPO by an equal amount and may result in EPO being allocated a loss when we are allocated income. Our participation in the expected future increase in cash flow from such projects after EPO receives its full Tier II distribution is limited (beyond our annualized return amount) to 2% of such upside, with EPO receiving 98% of the benefit.

The following table presents the allocation of net loss of the DEP II Midstream Businesses for the three months ended September 30, 2010:

		EPO	**DEP**
Total net loss of DEP II Midstream Businesses		$ (10.7)	$ (10.7)
Multiplied by each owner's Percentage Interest		77.4%	22.6%
Base earnings allocation to each owner		(8.3)	(2.4)
Additional earnings allocation to Duncan Energy Partners:			
Total distributions paid by the DEP II Midstream Businesses with respect to period	$ 35.6		
Multiplied by 22.6% Percentage Interest of Duncan Energy Partners	22.6%		
Duncan Energy Partners' Percentage Interest in the total cash distributions paid by the DEP II Midstream Businesses with respect to period	8.1		
Less actual distributions paid to Duncan Energy Partners with respect to period based on annualized return for period	(22.1)	(14.0)	14.0
Net loss attributable to EPO as noncontrolling interest		$ (22.3)	
Net income attributable to Duncan Energy Partners			$ 11.6

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The following table presents the allocation of net income of the DEP II Midstream Businesses for the three months ended September 30, 2009:

		EPO	DEP
Total net income of DEP II Midstream Businesses		$ 3.0	$ 3.0
Multiplied by each owner's Percentage Interest		77.4%	22.6%
Base earnings allocation to each owner		2.3	0.7
Additional earnings allocation to Duncan Energy Partners:			
Total distributions paid by the DEP II Midstream Businesses with respect to period	$ 29.4		
Multiplied by 22.6% Percentage Interest of Duncan Energy Partners	22.6%		
Duncan Energy Partners' Percentage Interest in the total cash distributions paid by the DEP II Midstream Businesses with respect to period	6.6		
Less actual distributions paid to Duncan Energy Partners with respect to period based on annualized return for period	(21.6)	(15.0)	15.0
Net loss attributable to EPO as noncontrolling interest		$ (12.7)	
Net income attributable to Duncan Energy Partners			$ 15.7

The following table presents the allocation of net loss of the DEP II Midstream Businesses for the nine months ended September 30, 2010:

		EPO	DEP
Total net loss of DEP II Midstream Businesses		$ (9.9)	$ (9.9)
Multiplied by each owner's Percentage Interest		77.4%	22.6%
Base earnings allocation to each owner		(7.7)	(2.2)
Additional earnings allocation to Duncan Energy Partners:			
Total distributions paid by the DEP II Midstream Businesses with respect to period	$ 97.6		
Multiplied by 22.6% Percentage Interest of Duncan Energy Partners	22.6%		
Duncan Energy Partners' Percentage Interest in the total cash distributions paid by the DEP II Midstream Businesses with respect to period	22.1		
Less actual distributions paid to Duncan Energy Partners with respect to period based on annualized return for period	(66.2)	(44.1)	44.1
Net loss attributable to EPO as noncontrolling interest		$ (51.8)	
Net income attributable to Duncan Energy Partners			$ 41.9

The following table presents the allocation of net income of the DEP II Midstream Businesses for the nine months ended September 30, 2009:

		EPO	DEP
Total net income of DEP II Midstream Businesses		$ 1.5	$ 1.5
Multiplied by each owner's Percentage Interest		77.4%	22.6%
Base earnings allocation to each owner		1.1	0.4
Additional earnings allocation to Duncan Energy Partners:			
Total distributions paid by the DEP II Midstream Businesses with respect to period	$ 83.6		
Multiplied by 22.6% Percentage Interest of Duncan Energy Partners	22.6%		
Duncan Energy Partners' Percentage Interest in the total cash distributions paid by the DEP II Midstream Businesses with respect to period	18.9		
Less actual distributions paid to Duncan Energy Partners with respect to period based on annualized return for period	(64.9)	(46.0)	46.0
Net loss attributable to EPO as noncontrolling interest		$ (44.9)	
Net income attributable to Duncan Energy Partners			$ 46.4

The DEP II Midstream Businesses distributed an aggregate of $35.6 million and $29.4 million for the three months ended September 30, 2010 and 2009, respectively. For the nine months ended September 30, 2010 and 2009, the DEP II Midstream Businesses distributed an aggregate of $97.6 and $83.6 million, respectively. Of these amounts, EPO received $13.5 million and $7.8 million for the three months ended September 30, 2010 and 2009, respectively, and $31.4 million and $18.7 million for the nine months ended September 30, 2010 and 2009, respectively.

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The $22.1 million and $66.2 million received by us from the DEP II Midstream Businesses with respect to the three and nine months ended September 30, 2010, respectively, represent approximately one-quarter and three-quarters, respectively, of the annualized return rate for 2010 of 12.087% multiplied by our Distribution Base of $730.0 million. As a result, we received our expected Tier I distributions for the periods indicated. Based on EPO's Distribution Base, it was entitled to $31.6 million and $87.5 million of Tier II distributions for the three and nine months ended September 30, 2010, respectively, of which it received $13.5 million and $31.4 million, respectively. No Tier III distributions were paid by the DEP II Midstream Businesses with resp ect to the nine months ended September 30, 2010.

The following table provides a reconciliation of the amount presented as "Noncontrolling interest in subsidiaries – DEP II Midstream Businesses – Parent," on our Unaudited Condensed Consolidated Balance Sheets at September 30, 2010:

December 31, 2009 balance	$	2,888.2
Allocated loss from DEP II Midstream Businesses to EPO as Parent		(51.8)
Contributions by EPO in connection with expansion cash calls		228.3
Distributions to noncontrolling interest of subsidiary operating cash flows		(34.7)
Return of contributions to EPO in connection with the transfer of an expansion capital project to Mont Belvieu Caverns		(25.4)
Other general contributions from noncontrolling interest, net		3.3
September 30, 2010 balance	$	3,007.9

For additional information regarding our agreements with EPO in connection with the DEP I or II drop down transaction, see "Significant Relationships and Agreements with EPO" under Note 13.

Note 12. Business Segments

We have three reportable business segments: (i) Natural Gas Pipelines & Services; (ii) NGL Pipelines & Services; and (iii) Petrochemical Services. Our business segments are generally organized and managed according to the type of services rendered (or technologies employed) and products produced and/or sold.

We evaluate segment performance based on the non-GAAP financial measure of gross operating margin. Gross operating margin (either in total or by individual segment) is an important performance measure of the core profitability of our operations. This measure forms the basis of our internal financial reporting and is used by management in deciding how to allocate capital resources among business segments. We believe that investors benefit from having access to the same financial measures that management uses in evaluating segment results. The GAAP financial measure most directly comparable to total segment gross operating margin is operating income. Our non-GAAP financial measure of total segment gross operating margin should not be c onsidered an alternative to GAAP operating income.

We define total segment gross operating margin as operating income before: (i) depreciation, amortization and accretion expenses; (ii) non-cash consolidated asset impairment charges; (iii) gains and losses from asset sales and related transactions and (iv) general and administrative costs. Gross operating margin by segment is calculated by subtracting segment operating costs and expenses (net of the adjustments noted above) from segment revenues, with both segment totals before the elimination of any intersegment and intrasegment transactions. In accordance with GAAP, intercompany accounts and transactions are eliminated in the preparation of our consolidated financial statements. Gross operating margin is exclusive of other income and expe nse transactions, provision for income taxes, extraordinary charges and the cumulative effect of changes in accounting principles. Gross operating margin is presented on a 100% basis before the allocation of earnings to noncontrolling interests.

The following table shows our measurement of total segment gross operating margin for the periods indicated:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2010	2009	2010	2009
Revenues	$ 283.7	$ 244.6	$ 839.5	$ 728.1
Less: Operating costs and expenses	(268.5)	(220.8)	(780.8)	(675.7)
Add: Equity in income of Evangeline	0.3	0.5	0.5	1.0
Depreciation, amortization and accretion in operating costs and expenses (1)	49.9	47.4	149.0	137.7
Non-cash impairment charge	--	--	1.5	--
Less: Losses (gains) from asset sales and related transactions in operating costs and expenses (2)	9.0	(0.1)	8.0	(0.4)
Total segment gross operating margin	$ 74.4	$ 71.6	$ 217.7	$ 190.7

(1) Amount is a component of “Depreciation, amortization and accretion” as presented on our Unaudited Condensed Statements of Consolidated Cash Flows.

(2) Amount presented for the three and nine months ended September 30, 2010 includes a $9.1 million loss related to the disposal of a non-strategic pipeline segment owned by Enterprise Texas.

The following table presents a reconciliation of our non-GAAP total segment gross operating margin to GAAP operating income and income before benefit from (provision for) income taxes for the periods indicated:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2010	2009	2010	2009
Total segment gross operating margin	$ 74.4	$ 71.6	$ 217.7	$ 190.7
Adjustments to reconcile total segment gross operating margin to operating income:				
Depreciation, amortization and accretion in operating costs and expenses	(49.9)	(47.4)	(149.0)	(137.7)
Non-cash impairment charge	--	--	(1.5)	--
Gains (losses) from asset sales and related transactions in operating costs and expenses	(9.0)	0.1	(8.0)	0.4
General and administrative costs	(6.4)	(3.2)	(16.1)	(8.8)
Operating income	9.1	21.1	43.1	44.6
Other expense, net	(2.9)	(3.4)	(9.2)	(10.5)
Income before benefit from (provision for) income taxes	$ 6.2	$ 17.7	$ 33.9	$ 34.1

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Information by segment, together with reconciliations to our consolidated totals, is presented in the following table:

	Natural Gas Pipelines & Services	NGL Pipelines & Services	Petrochemical Services	Adjustments and Eliminations	Consolidated Totals
Revenues from third parties:					
Three months ended September 30, 2010	$ 83.2	$ 25.1	$ 3.7	$ --	$ 112.0
Three months ended September 30, 2009	94.4	18.1	3.5	--	116.0
Nine months ended September 30, 2010	306.6	77.4	10.4	--	394.4
Nine months ended September 30, 2009	261.7	64.6	10.2	--	336.5
Revenues from related parties:					
Three months ended September 30, 2010	131.3	40.4	--	--	171.7
Three months ended September 30, 2009	89.7	38.9	--	--	128.6
Nine months ended September 30, 2010	336.0	109.1	--	--	445.1
Nine months ended September 30, 2009	290.9	100.7	--	--	391.6
Total revenues:					
Three months ended September 30, 2010	214.5	65.5	3.7	--	283.7
Three months ended September 30, 2009	184.1	57.0	3.5	--	244.6
Nine months ended September 30, 2010	642.6	186.5	10.4	--	839.5
Nine months ended September 30, 2009	552.6	165.3	10.2	--	728.1
Equity in income of Evangeline:					
Three months ended September 30, 2010	0.3	--	--	--	0.3
Three months ended September 30, 2009	0.5	--	--	--	0.5
Nine months ended September 30, 2010	0.5	--	--	--	0.5
Nine months ended September 30, 2009	1.0	--	--	--	1.0
Gross operating margin:					
Three months ended September 30, 2010	46.3	25.5	2.6	--	74.4
Three months ended September 30, 2009	40.5	28.3	2.8	--	71.6
Nine months ended September 30, 2010	125.9	84.0	7.8	--	217.7
Nine months ended September 30, 2009	109.5	73.3	7.9	--	190.7
Segment assets:					
At September 30, 2010	3,498.9	964.4	81.2	577.0	5,121.5
At December 31, 2009	3,340.8	946.1	83.4	233.6	4,603.9
Property, plant and equipment: (see Note 6)					
At September 30, 2010	3,477.4	935.8	81.2	577.0	5,071.4
At December 31, 2009	3,318.8	913.8	83.4	233.6	4,549.6
Investment in Evangeline: (see Note 7)					
At September 30, 2010	6.1	--	--	--	6.1
At December 31, 2009	5.6	--	--	--	5.6
Intangible assets: (see Note 8)					
At September 30, 2010	11.0	28.1	--	--	39.1
At December 31, 2009	12.0	31.8	--	--	43.8
Goodwill: (see Note 8)					
At September 30, 2010	4.4	0.5	--	--	4.9
At December 31, 2009	4.4	0.5	--	--	4.9

The following table provides additional information regarding our consolidated revenues and costs and expenses for the periods indicated:

	For the Three Months Ended September 30, 2010	For the Three Months Ended September 30, 2009	For the Nine Months Ended September 30, 2010	For the Nine Months Ended September 30, 2009
Natural Gas Pipelines & Services:				
Sales of natural gas	$ 139.0	$ 113.6	$ 419.6	$ 348.9
Natural gas transportation services	71.8	66.1	210.8	192.5
Natural gas storage services	3.7	4.4	12.2	11.2
Total	214.5	184.1	642.6	552.6
NGL Pipelines & Services:				
Sales of NGLs	10.2	9.4	31.2	24.3
Sales of other products	4.5	2.3	12.7	8.6
NGL and petrochemical storage services	30.8	26.7	86.7	76.4
NGL fractionation services	8.1	7.2	22.2	22.0
NGL transportation services	11.4	10.8	32.2	32.0
Other services	0.5	0.6	1.5	2.0
Total	65.5	57.0	186.5	165.3
Petrochemical Services:				
Propylene transportation services	3.7	3.5	10.4	10.2
Total consolidated revenues	$ 283.7	$ 244.6	$ 839.5	$ 728.1
Consolidated costs and expenses:				
Operating costs and expenses:				
Cost of natural gas and NGL sales	$ 145.8	$ 116.7	$ 441.5	$ 362.3
Depreciation, amortization and accretion	49.9	47.4	149.0	137.7
Losses (gains) from asset sales and related transactions	9.0	(0.1)	8.0	(0.4)
Other operating expenses	63.8	56.8	182.3	176.1
General and administrative costs	6.4	3.2	16.1	8.8
Total consolidated costs and expenses	$ 274.9	$ 224.0	$ 796.9	$ 684.5

Changes in our revenues and operating costs and expenses period-to-period are due in part to changes in energy commodity prices. In general, higher energy commodity prices result in an increase in our revenues attributable to the sale of natural gas and NGLs; however, these higher commodity prices also increase the associated cost of sales as purchase prices rise.

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Note 13. Related Party Transactions

The following table summarizes our related party transactions for the periods indicated:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2010	2009	2010	2009
Revenue:				
Revenues from EPO:				
Sales of natural gas	$ 39.9	$ 27.0	$ 102.0	$ 109.5
Natural gas transportation services	32.5	12.2	86.8	36.1
Natural gas storage services	--	0.7	1.3	1.9
Sales of NGLs	14.2	15.2	34.6	28.8
NGL and petrochemical storage services	9.9	9.1	28.2	27.6
NGL fractionation services	8.1	6.9	22.2	21.1
NGL transportation services	8.0	7.4	23.9	22.9
Sales of natural gas – Evangeline	58.9	49.8	145.7	143.3
Natural gas transportation services – Energy Transfer Equity	--	--	0.2	0.1
NGL and petrochemical storage services – Energy Transfer Equity	0.2	0.3	0.2	0.3
Total related party revenues	$ 171.7	$ 128.6	$ 445.1	$ 391.6
Operating costs and expenses:				
EPCO ASA	$ 23.1	$ 25.1	$ 66.5	$ 64.2
Expenses with EPO:				
Purchases of natural gas	24.2	13.0	53.5	47.5
Operational measurement losses (gains)	(2.6)	(0.8)	(7.0)	1.8
Other expenses with EPO	3.7	3.8	12.5	12.5
Purchases of natural gas – Nautilus	--	(0.1)	0.2	1.7
Expenses with Energy Transfer Equity:				
Purchases of natural gas (1)	2.1	1.7	7.9	(1.5)
Operating cost reimbursements for shared facilities	(0.5)	(0.9)	(2.4)	(2.6)
Other expenses with Energy Transfer Equity	(2.1)	0.4	(0.8)	1.1
Total related party operating costs and expenses	$ 47.9	$ 42.2	$ 130.4	$ 124.7
General and administrative costs:				
EPCO ASA	$ 5.9	$ 2.9	$ 13.4	$ 7.8
Other income (expense) transactions:				
Interest expense on note payable to EPO	$ (0.6)	$ --	$ (0.6)	$ --

(1) Amounts include gas imbalances of $(2.4) million and $(0.5) million with Energy Transfer Equity for the three months ended September 30, 2010 and 2009, respectively and gas imbalances of $(2.5) million and $(6.0) million with Energy Transfer Equity for the nine months ended September 30, 2010 and 2009, respectively.

The following table summarizes our related party receivable and payable amounts at the dates indicated:

	September 30, 2010	December 31, 2009
Accounts receivable – related parties:		
EPO and affiliates (1)	$ 9.8	$ 47.0
Evangeline	15.7	7.3
Energy Transfer Equity and affiliates	0.7	0.2
Total	$ 26.2	$ 54.5
Accounts payable – related parties:		
EPO and affiliates	$ 18.4	$ 5.5
EPCO and affiliates	9.1	8.1
Total	$ 27.5	$ 13.6
Accrued interest payable – related parties:		
EPO (2)	$ 0.2	$ --

(1) In December 2009, EPO borrowed $45.6 million under a master intercompany loan agreement, which was subsequently repaid in January 2010. See "Significant Relationships and Agreements with EPO" under this Note 13 for more information.
(2) Our accrued interest payable with EPO is a component of "Other current liabilities" as presented on our Unaudited Condensed Consolidated Balance Sheets.

We believe that the terms and provisions of our related party agreements are fair to us; however, such agreements and transactions may not be as favorable to us as we could have obtained from unaffiliated third parties.

Significant Relationships and Agreements with EPO

Our assets are integral to EPO's midstream energy operations. We believe that the operational significance of our assets to EPO, as well as the alignment of our respective economic interests in these assets, will result in a collaborative effort to promote their operational efficiency and maximize value. In addition, we believe our relationship with EPO and EPCO provides us with a distinct benefit in both the operation of our assets and in the identification and execution of potential future acquisitions that are not otherwise taken by Enterprise Products Partners or Holdings in accordance with our business opportunity agreements. One of our primary business purposes is to support the growth objectives of EPO and other affiliates of EPCO that are under common control.

At September 30, 2010, EPO owned approximately 58.5% of our limited partner interests and 100% of our general partner. EPO was the sponsor of the DEP I and DEP II drop down transactions and owns noncontrolling economic interests in the DEP I and DEP II Midstream Businesses. For a description of EPO's noncontrolling interest in the income and net assets of the DEP I and DEP II Midstream Businesses, see Note 11. EPO may contribute or sell other equity interests or assets to us; however, EPO has no obligation or commitment to make such contributions or sales to us, nor do we have any obligation or commitment to accept such contributions or make such acquisitions.

EPO has continuing involvement with our subsidiaries, including the following: (i) it utilizes our storage services to support its operations at Mont Belvieu, Texas; (ii) it buys from, and sells to, us natural gas in connection with its normal business activities; and (iii) it is currently the sole shipper on an NGL pipeline system located in south Texas that we own.

Master Intercompany Loan Agreement. On December 31, 2009, we and EPO entered into a master intercompany loan agreement with the DEP I and DEP II Midstream Businesses. This agreement will be used from time to time to facilitate cash management efforts in connection with the DEP I and DEP II Midstream Businesses. On December 31, 2009, we and EPO borrowed $1.3 million and $45.6 million, respectively, under the agreement at a market rate of interest. EPO's intercompany borrowing is a component of "Accounts receivable – related parties" on our Unaudited Condensed Consolidated Balance Sheets at December 31, 2009. These amounts were subsequently repaid on January 4, 2010. The interest rate applicable to these short-term borrowings was 0.73% per annum. Amounts borrowed by us and the related interest eliminate in consolidation. There were no loans issued under this agreement during the nine months ended September 30, 2010.

Loan Agreement with EPO. On June 1, 2010, we entered into a loan agreement with EPO. We had borrowings of $125.0 million under the Loan Agreement with EPO at September 30, 2010. See Note 9 for additional information regarding this related party agreement.

Omnibus Agreement. On December 8, 2008, we entered into an amended and restated Omnibus Agreement (the "Omnibus Agreement") with EPO that addressed various matters. The key provisions of this agreement at September 30, 2010 are summarized as follows:

§ EPO was granted a right of first refusal in our current and future subsidiaries and a right of first refusal on the material assets of such subsidiaries, other than sales of inventory and other assets in the ordinary course of business;

§ EPO was granted a preemptive right with respect to any equity securities issued by certain of our subsidiaries, other than those that may be issued as consideration in an acquisition or in connection with a loan or debt financing;

§ Neither EPO nor any of its affiliates are restricted under the Omnibus Agreement from competing against us;

§ We and EPO agreed to negotiate in good faith any necessary amendments to the partnership or company agreements of the DEP II Midstream Businesses when either party believes that business circumstances have changed; and

§ Our general partner's Audit, Conflicts and Governance Committee must approve amendments to the Omnibus Agreement when such amendments would adversely affect our unitholders.

Under the Omnibus Agreement, EPO also indemnified us for certain environmental liabilities, tax liabilities and right-of-way defects associated with the assets it contributed to us in connection with the DEP I and DEP II dropdown transactions. These indemnifications terminated on February 5, 2010. No claims were made under the indemnification agreement.

Mont Belvieu Caverns' LLC Agreement. As a key provision, the Caverns LLC Agreement dated November 1, 2008 states that if Duncan Energy Partners elects to not participate in the expansion projects of Mont Belvieu Caverns, then EPO is responsible for funding 100% of such projects. To the extent such non-participated projects generate identifiable incremental cash flows for Mont Belvieu Caverns in the future, the earnings and cash flows of Mont Belvieu Caverns will be adjusted to allocate such incremental amounts to EPO, by special allocation or otherwise. Under the terms of the Caverns LLC Agreement, Duncan Energy Par tners may elect to acquire a 66% share of these expansion projects from EPO within 90 days of such projects being placed in service. The Caverns LLC Agreement provides for EPO, effective November 2008, to prospectively receive a special allocation of 100% of the depreciation related to expansion projects that it has fully funded. The Caverns LLC Agreement also requires the allocation to EPO of operational measurement gains and losses. See Note 11 for information regarding the allocation of operational measurement gains and losses to EPO as well as EPO's funding of expansion projects under Caverns LLC Agreement.

Company and Limited Partnership Agreements – DEP II Midstream Businesses. On December 8, 2008, the DEP II Midstream Businesses amended and restated their governing documents in connection with the DEP II drop down transaction. Collectively, these amendments include, but are not limited to, (i) the payment of cash distributions in accordance with an overall "waterfall" approach, (ii) the funding of operating cash flow deficits and (iii) the election by either owner to fund cash calls associated with expansion capital projects. See Note 11 for information regarding EPO's noncontrolling interest and related matters involving the DEP II Midstream Businesses.

Amended Acadian LLC Agreement. On June 1, 2010, we entered into the Amended Acadian LLC Agreement with EPO. As part of this agreement, we and EPO agreed to fund the construction of the Haynesville Extension in accordance with our respective sharing ratios in Acadian Gas (i.e., 66% for us and 34% for EPO). The total expected cost of the Haynesville Extension is approximately $1.56 billion (including capitalized interest); therefore, we estimate that our share of such costs will approximate $1.03 billion. In order to address our funding requirements under the Haynesville Extension project, we entered into new long-term senior unsecured credit facilities in Oc tober 2010 having an aggregate borrowing capacity of $1.25 billion (see Note 9).

As part of the agreement, we reimbursed EPO for 66% of certain construction expenses it paid related to the Haynesville Extension project from the inception of the project through the date of the agreement (plus interest). In June 2010, Acadian Gas acquired a purchase order, originally held by EPO for a previous project, for approximately 175 miles of pipe with a value of $167.4 million. This pipe will be used in the construction of the Haynesville Extension. Acadian Gas reimbursed EPO approximately $90.9 million for its prior payments on this order of pipe, of which our 66% share was approximately $60.0 million.

The Amended Acadian LLC Agreement also includes provisions related to future expansion projects of Acadian Gas other than the Haynesville Extension. When such projects are presented for funding, Acadian Gas will request additional capital contributions from us and EPO based on our respective sharing ratios. Acadian Gas will provide us and EPO with written notice of the due date for our initial contributions and we and EPO will have 20 days to give a written reply as to whether we elect to participate in the expansion project. We or EPO may propose to contribute an amount less than that requested by Acadian Gas, at which time we and EPO will decide whether to proceed with the expansion project.

Relationship with EPCO

We have no employees. All of our operating functions and general and administrative support services are provided by employees of EPCO pursuant the ASA or by other service providers. We, Enterprise Products Partners, Holdings and our respective general partners are parties to the ASA. The significant terms of the ASA are as follows:

§ EPCO will provide selling, general and administrative services and management and operating services as may be necessary to manage and operate our businesses, properties and assets (all in accordance with prudent industry practices). EPCO will employ or otherwise retain the services of such personnel as may be necessary to provide such services.

§ We are required to reimburse EPCO for its services in an amount equal to the sum of all costs and expenses incurred by EPCO which are directly or indirectly related to our business or activities (including expenses reasonably allocated to us by EPCO). In addition, we have agreed to pay all sales, use, excise, value added or similar taxes, if any, that may be applicable from time to time with respect to the services provided to us by EPCO.

§ EPCO will allow us to participate as a named insured in its overall insurance program, with the associated premiums and other costs being allocated to us. See Note 16 for additional information regarding our insurance programs.

Our operating costs and expenses include amounts paid to EPCO for the costs it incurs to operate our facilities, including the compensation of employees. We reimburse EPCO for actual direct and indirect expenses it incurs related to the operation of our assets. Our general and administrative costs include amounts paid to EPCO for administrative services, including the compensation of employees. In general, our reimbursement to EPCO for administrative services is either (i) on an actual basis for direct expenses it may incur on our behalf (e.g., the purchase of office supplies) or (ii) based on an allocation of such charges between the various parties to the ASA based on the estimated use of such services by each party (e.g., the allocation of legal or accounting salaries based on estimates of time spent on each entity's business and affairs).

Since the vast majority of such expenses charged to us under the ASA are on an actual basis (i.e. no mark-up or subsidy is charged or received by EPCO), we believe that such expenses are representative of what the amounts would have been on a standalone basis. With respect to allocated costs, we believe that the proportional direct allocation method employed by EPCO is reasonable and reflective of the estimated level of costs we would have incurred on a standalone basis.

The ASA also addresses potential conflicts that may arise among Enterprise Products Partners (including EPGP), Holdings (including EPE Holdings), Duncan Energy Partners (including DEP GP), and the EPCO Group with respect to business opportunities (as defined within the ASA) with third parties. The EPCO Group includes EPCO and its other affiliates, but excludes Enterprise Products Partners, Holdings, Duncan Energy Partners and their respective general partners.

Relationship with Evangeline

Acadian Gas sold $58.9 million and $49.8 million of natural gas to Evangeline, under its natural gas purchase contract with Evangeline, during the three months ended September 30, 2010 and 2009, respectively. For the nine months ended September 30, 2010 and 2009, Acadian Gas sold $145.7 million and $143.3 million, respectively, of natural gas to Evangeline. The amount of natural gas purchased by Evangeline pursuant to this contract averaged approximately 66.1 BBtus per day ("BBtus/d") and 71.3 BBtus/d during the three months ended September 30, 2010 and 2009, respectively, and 49.6 BBtus/d and 53.8 BBtus/d during the nine months ended September 30, 2010 and 2009, respectively.

Relationship with Energy Transfer Equity

Holdings acquired equity method investments in Energy Transfer Equity and its general partner in May 2007. As a result of the common control of Holdings and us, Energy Transfer Equity became a related party to us. Our revenues from Energy Transfer Equity are attributable to natural gas transportation services. Our related party expenses with Energy Transfer Equity primarily include natural gas purchases for pipeline imbalances, reimbursements of operating costs for shared facilities and the lease of a pipeline in South Texas.

Note 14. Earnings Per Unit

Basic earnings per unit is computed by dividing net income or loss allocated to limited partner interests by the weighted-average number of distribution-bearing units outstanding during a period. We have no dilutive securities.

The amount of net income or loss allocated to limited partner interests is net of our general partner's share of such earnings. The following table presents the allocation of net income to DEP GP for the periods indicated:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2010	2009	2010	2009
Net income attributable to Duncan Energy Partners L.P.	$ 20.6	$ 24.8	$ 65.1	$ 67.9
Multiplied by DEP GP ownership interest	0.7%	0.7%	0.7%	0.7%
Net income allocation to DEP GP	$ 0.2	$ 0.2	$ 0.5	$ 0.5

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The following table presents our calculation of basic and diluted earnings per unit for the periods indicated:

	For the Three Months Ended September 30, 2010	For the Three Months Ended September 30, 2009	For the Nine Months Ended September 30, 2010	For the Nine Months Ended September 30, 2009
Net income allocation to Duncan Energy Partners	$ 20.6	$ 24.8	$ 65.1	$ 67.9
Less: Income allocation to DEP GP	(0.2)	(0.2)	(0.5)	(0.5)
Net income allocation to limited partners	$ 20.4	$ 24.6	$ 64.6	$ 67.4
Basic and diluted earnings per unit:				
Numerator (net income allocation to limited partners)	$ 20.4	$ 24.6	$ 64.6	$ 67.4
Denominator (weighted-average common units outstanding):				
Common units	57.7	57.7	57.7	57.7
Earnings per unit	$ 0.36	$ 0.43	$ 1.12	$ 1.17

Note 15. Commitments and Contingencies

Litigation

As part of our normal business activities, we are named on occasion as a defendant in litigation and legal proceedings, including those arising from regulatory and environmental matters. Although we are insured against various risks to the extent we believe it is prudent, there is no assurance that the nature and amount of such insurance will be adequate, in every case, to indemnify us against liabilities arising from future legal proceedings. See Note 16 for information regarding our insurance program. We are not aware of any litigation, pending or threatened, that we believe is reasonably likely to have a significant adverse effect on our consolidated financial position, results of operations or cash flows.

Our reserve for litigation contingencies totaled $6.8 million at September 30, 2010 and relates to a contractual dispute involving our South Texas NGL pipeline system owned by Enterprise GC (a DEP II Midstream Business) that began prior to its acquisition from a third party in September 2004. This reserve was established during the third quarter of 2010 due to the specific facts and circumstances of the underlying litigation. Our evaluation of litigation contingencies is based on the facts and circumstances of each case and predicting the outcome of these matters involves substantial uncertainties. In the event the assumptions we use to evaluate these matters change in future periods or new information becomes available, we may be required to record a liability for an adverse outcome. In an effort to mitigate potential adverse consequences of litigation, we may settle legal proceedings out of court.

Redelivery Commitments

We transport and store natural gas and NGLs and store petrochemical products for customers under various contracts. These volumes are (i) accrued as product payables on our Unaudited Condensed Consolidated Balance Sheets, (ii) in transit for delivery to our customers or (iii) held at our storage facilities for redelivery to our customers. We are insured against any physical loss of such volumes due to catastrophic events. Under the terms of our NGL and petrochemical product storage agreements, we are generally required to redeliver volumes to the owner on demand. At September 30, 2010 and December 31, 2009, NGL and petrochemical products aggregating 21.7 million barrels and 20.9 million barrels, respectively, were due to be redelivered to their owners along with 5,208 BBtus and 5,015 BBtus, respectively, of natural gas.

Regulatory Matters

Certain scientific studies have suggested that emissions of certain gases, commonly referred to as “greenhouse gases” and including carbon dioxide (which is a component of, and a product of combustion of, natural gas) and methane (which is a component of natural gas), may be contributing to global climate change and ocean acidification. On June 26, 2009, the U.S. House of Representatives passed the American Clean Energy and Security Act of 2009 ("ACESA") which, if it were to become law, would establish an economy-wide cap-and-trade program intended to reduce the emissions of greenhouse gases by the United States and would require most significant domestic sources of greenhouse gas emissions to obtain greenhouse gas emission "allowances" corresponding to their annual emissions of greenhouse gases. The U.S. Senate has also begun consideration of various legislative proposals for controlling and reducing emissions of greenhouse gases in the United States. In addition, on December 7, 2009, the U.S. Environmental Protection Agency ("EPA") announced its finding that emission s of greenhouse gases from motor vehicles caused or contributed to climate change and presented an endangerment to human health and the environment. These findings by the EPA were the basis for motor vehicle greenhouse gas emissions standards promulgated on May 7, 2010, and may allow the agency to proceed with the adoption and implementation of additional regulations that would require permits or control emissions of greenhouse gases from industrial sources under existing provisions of the federal Clean Air Act. On May 13, 2010, the EPA issued a final rule setting forth a timetable for its Title V and Prevention of Significant Deterioration regulatory program, applicable in certain circumstances to new and modified industrial source of air emissions, to include consideration of greenhouse gas emissions. The EPA has also received petitions requesting that the agency further expand regulation of greenhouse gas emissions from industrial sources, which, over time, may lead to add itional requirements. On April 12, 2010, the EPA proposed new rules that would require the mandatory reporting of greenhouse gas emissions by operators of natural gas compression, processing and storage facilities. These rules supplement disclosures and reporting required by the EPA in its October 30, 2009 mandatory greenhouse gas reporting rule. These and any new laws or regulations that may be adopted to restrict or reduce emissions of greenhouse gases, or that establish new reporting requirements, will require us to incur increased operating costs, and may have an adverse effect on our financial position, results of operations and cash flows.

Contractual Obligations

Scheduled maturities of long-term debt. Amounts owed under our debt agreements have increased since December 31, 2009 primarily due to borrowings to fund construction costs of the Haynesville Extension. In October 2009, amounts due under our Revolving Credit Facility and the Loan Agreement with EPO were repaid using borrowings under new long-term credit facilities that mature in October 2013. See Note 9 for information regarding this subsequent event.

Operating lease obligations. We lease certain property, plant and equipment under noncancelable and cancelable operating leases. Our significant lease agreements involve (i) the lease of underground caverns for the storage of natural gas and NGLs, primarily our lease for the Wilson natural gas storage facility and (ii) land held pursuant to right-of-way agreements. There have been no material changes in our operating lease commitments since those reported in our 2009 Form 10-K/A.

Lease expense is charged to operating costs and expenses on a straight line basis over the period of expected economic benefit. Contingent rental payments are expensed as incurred. We are generally required to perform routine maintenance on the underlying leased assets. In addition, certain leases give us the option to make leasehold improvements. Maintenance and repairs of leased assets resulting from our operations are charged to expense as incurred. Lease and rental expense was $3.5 million and $2.8 million during the three months ended September 30, 2010 and 2009, respectively. Lease and rental expense was $10.0 million and $7.8 million during the nine months ended September 30, 2010 and 2009, respectively.

Purchase obligations. There have been no material changes in our consolidated purchase obligations since those reported in our 2009 Form 10-K/A, except for short-term payment obligations relating to capital projects. These commitments represent unconditional payment obligations that we have agreed to pay vendors for services to be rendered or products to be delivered in connection with our capital spending programs. Our consolidated capital expenditure commitments outstanding increased from $175.3 million at December 31, 2009 to $450.6 million at September 30, 2010. At September 30, 2010, these commitments primarily relate to the Haynesville Extension and projects on the Texas Intrastate System.

Other Claims

As part of our normal business activities with joint venture partners, customers and suppliers, we occasionally have claims made against us as a result of disputes related to contractual agreements or other communications. These matters are in various stages of assessment and the ultimate outcome of such disputes cannot be reasonably estimated at this time. However, in our opinion, the likelihood of a material adverse outcome to us resulting from such disputes is remote. Accordingly, we have not recorded any accruals for loss contingencies related to these matters. As of September 30, 2010, claims against us totaled approximately $1.2 million.

Note 16. Significant Risks and Uncertainties

Insurance-Related Risks

We participate as a named insured in EPCO's insurance program, which provides us with property damage, business interruption and other coverages, the scope and amounts of which we believe are customary and prudent for the nature and extent of our operations. While we believe EPCO maintains adequate insurance coverage on our behalf, insurance will not cover every type of damage or interruption that might occur. If we were to incur a significant liability for which we were not fully insured, it could have a material impact on our consolidated financial position, results of operations and cash flows. In addition, the proceeds of any such insurance may not be paid in a timely manner and may be insufficient to reimburse us for our repair costs or lost income. Any event that interrupts the revenues generated by our consolidated operations, or which causes us to make significant expenditures not covered by insurance, could reduce our ability to pay distributions to our partners and, accordingly, adversely affect the market price of our common units.

EPCO completed its annual insurance renewal process during the second quarter of 2010, which resulted in an increase in premiums. EPCO's deductible for onshore physical damage from windstorms increased from $25.0 million per storm to $30.0 million per storm. EPCO's onshore insurance program currently provides $141.3 million of coverage per occurrence for named windstorm events compared to $150.0 million per occurrence in the prior year. With respect to offshore assets, the deductible for windstorm damage remained at $75.0 million per storm. EPCO's insurance program for offshore Gulf of Mexico assets currently provides $124.5 million of coverage in the aggregate compared to $100.0 million of coverage in the aggregate for the prior year. In addition, at EPCO' s election, we now have access to an additional $17.5 million of coverage for either onshore or offshore windstorm-related damage claims. For non-windstorm events, EPCO's deductible for both onshore and offshore physical damage remained at $5.0 million per occurrence.

Business interruption coverage in connection with a windstorm event remains in place for onshore assets. We do not have any business interruption coverage for our offshore Gulf of Mexico assets (e.g., the near-shore natural gas gathering pipelines of our TPC Offshore system, which is a component of our Texas Intrastate System) when the outage is due to a windstorm. We have business interruption coverage for both onshore and offshore assets in connection with non-windstorm events. Assets covered by business interruption insurance must be out-of-service in excess of 60 days before any allowed losses from business interruption will be covered.

At September 30, 2010, we did not have any estimated property damage claims.

Interest Rate Risk

We are exposed to changes in interest rates charged on our variable rate debt obligations. Our $175 million of floating-to-fixed interest rate swaps, which partially hedged our exposure to changes in variable interest rates on our Revolving Credit Facility, expired in September 2010. In October 2010, we executed new long-term variable rate senior unsecured credit facilities having an aggregate borrowing capacity of $1.25 billion. See Note 9 for additional information regarding this subsequent event.

Note 17. Supplemental Cash Flow Information

The following table provides information regarding the net effect of changes in our operating assets and liabilities.

	For the Nine Months Ended September 30,	
	2010	2009
Decrease (increase) in:		
Accounts receivable – trade	$ 7.2	$ 55.1
Accounts receivable – related parties	(18.8)	(0.3)
Inventories	0.3	15.6
Prepaid and other current assets	(2.1)	(4.8)
Increase (decrease) in:		
Accounts payable – trade	9.1	11.1
Accounts payable – related parties	16.1	(38.1)
Accrued product payables	(10.5)	(59.8)
Accrued property taxes	4.0	3.2
Accrued taxes – other	(0.6)	(2.1)
Other current liabilities	13.5	(13.1)
Other long-term liabilities	--	(0.2)
Net effect of changes in operating accounts	$ 18.2	$ (33.4)

We incurred liabilities for construction in progress that had not been paid at September 30, 2010 and December 31, 2009 of $75.9 million and $41.8 million, respectively. Such amounts are not included under the caption “Capital expenditures” on the Unaudited Condensed Statements of Consolidated Cash Flows.

Third parties may be obligated to reimburse us for all or a portion of expenditures on certain of our capital projects. The majority of such arrangements are associated with projects related to pipeline construction and producer well tie-ins. These amounts are included under the caption “Contributions in aid of construction costs” on the Unaudited Condensed Statements of Consolidated Cash Flows.

The following table presents the components of depreciation, amortization and accretion for the periods indicated:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2010	2009	2010	2009
Depreciation, amortization and accretion expense:				
DEP I Midstream Businesses	$ 11.6	$ 9.8	$ 31.8	$ 28.9
DEP II Midstream Businesses	41.5	37.5	120.1	108.6
Duncan Energy Partners L.P. standalone	(1.1)	0.6	0.6	1.6
Total	$ 52.0	$ 47.9	$ 152.5	$ 139.1

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Item 2. ***Management's Discussion and Analysis of Financial Condition and Results of Operations*.**

For the three and nine months ended September 30, 2010 and 2009.

The following information should be read in conjunction with our unaudited condensed consolidated financial statements and accompanying notes included in this quarterly report on Form 10-Q. The following information and such unaudited condensed consolidated financial statements should also be read in conjunction with the audited financial statements and related notes, together with our discussion and analysis of financial position and results of operations, included under Item 7 of our Annual Report for the year ended December 31, 2009, as initially filed on Form 10-K on March 1, 2010, and as amended on Form 10-K/A on May 21, 2010 ("2009 Form 10-K/A"). Our financial statements have been prepared in accordance with generally accepted accounting principles (220;GAAP") in the United States.

Key References Used in this Quarterly Report

Unless the context requires otherwise, references to "we," "us," "our," or "Duncan Energy Partners" are intended to mean the business and operations of Duncan Energy Partners L.P. and its consolidated subsidiaries. References to "DEP GP" mean DEP Holdings, LLC, which is our general partner. DEP GP is responsible for managing the business and operations of Duncan Energy Partners. References to "DEP OLP" mean DEP Operating Partnership, L.P., which is a wholly owned subsidiary of Duncan Energy Partners. Duncan Energy Partners conducts substantially all of its business through DEP OLP and its consolidated subsidiaries.

References to "Enterprise Products Partners" mean the business and operations of Enterprise Products Partners L.P. and its consolidated subsidiaries. Enterprise Products Partners is a publicly traded Delaware limited partnership, the common units of which are listed on the New York Stock Exchange ("NYSE") under the ticker symbol "EPD." References to "EPGP" mean Enterprise Products GP, LLC, which is the general partner of Enterprise Products Partners. References to "EPO" mean Enterprise Products Operating LLC, which is a wholly owned subsidiary of Enterprise Products Partners. Enterprise Products Partners conducts substan tially all of its business through EPO and its consolidated subsidiaries. EPO beneficially owns 100% of DEP GP and currently owns 58.5% of our common units. Enterprise Products Partners consolidates our financial statements with its own.

References to "Holdings" mean Enterprise GP Holdings L.P., a publicly traded Delaware limited partnership, the units of which are listed on the NYSE under the ticker symbol "EPE." Holdings owns EPGP. The general partner of Holdings is EPE Holdings, LLC ("EPE Holdings"), which is a wholly owned subsidiary of Dan Duncan LLC. On September 3, 2010, Holdings and Enterprise Products Partners entered into an Agreement and Plan of Merger that would, if approved by Holdings' unitholders, result in the merger of Holdings with a wholly owned subsidiary of Enterprise Products Partners through a unit-for-unit exchange.

The membership interests of Dan Duncan LLC are owned of record by a voting trust formed on April 26, 2006, pursuant to the Dan Duncan LLC Voting Trust Agreement dated April 26, 2006 (the "DD LLC Voting Trust Agreement"), among Dan Duncan LLC and Dan L. Duncan (as the record owner of all of the membership interests of Dan Duncan LLC immediately prior to the entering into of the DD LLC Voting Trust Agreement and as the initial sole voting trustee).

Immediately upon Mr. Duncan's death on March 29, 2010, voting and dispositive control of all of the membership interests of Dan Duncan LLC was transferred pursuant to the DD LLC Voting Trust Agreement to three voting trustees. The current voting trustees under the DD LLC Voting Trust Agreement (the "DD LLC Trustees") are: (i) Randa Duncan Williams, Mr. Duncan's oldest daughter, who is also a director of EPE Holdings; (ii) Dr. Ralph S. Cunningham, who is currently the President and Chief Executive Officer ("CEO") of EPE Holdings; and (iii) Richard H. Bachmann, who is currently an Executive Vice President, the Chief Legal Officer and Secretary of EPGP and one of three managers of Dan Duncan LLC. Dr. Cunningham and Mr. Bachmann also serve as directors of EPE Holdings.

The DD LLC Voting Trust Agreement requires that there always be two "Independent Voting Trustees" serving. If Mr. Bachmann or Dr. Cunningham fail to qualify or cease to serve, then the substitute or successor Independent Voting Trustee(s) will be appointed by the then-serving Independent Voting Trustee, provided that if no Independent Voting Trustee is then serving or if a vacancy in a trusteeship of an Independent Voting Trustee is not filled within ninety days of the vacancy's occurrence, the CEO of EPGP, currently Michael A. Creel, will appoint the successor Independent Voting Trustee(s).

The DD LLC Voting Trust Agreement also provides for a "Duncan Voting Trustee." The Duncan Voting Trustee is appointed by the children of Mr. Duncan acting by a majority or, if less than three children of Mr. Duncan are then living, unanimously. If for any reason no descendent of Mr. Duncan is appointed as the Duncan Voting Trustee, then such trusteeship will remain vacant until such time as a Duncan Voting Trustee is appointed in the manner provided above. If a Duncan Voting Trustee for any reason ceases to serve, his or her successor shall be appointed by the children of Mr. Duncan acting by majority or, if less than three children of Mr. Duncan are then living, unanimously. Ms. Williams is currently the Duncan Voting Trustee.

The estate of Mr. Duncan became the sole member party to the DD LLC Voting Trust Agreement upon the death of Mr. Duncan on March 29, 2010. For all purposes whatsoever, the DD LLC Trustees are required to treat the member party to the DD LLC Voting Trust Agreement as the beneficial owner of the membership interests of Dan Duncan LLC. However, the DD LLC Trustees collectively are the record owners of the Dan Duncan LLC membership interests and possess and are entitled to exercise all rights and powers of absolute ownership thereof and to vote, assent or consent with respect thereto and to take party in and consent to any corporate or members' actions (except those actions, if any, to which the DD LLC Trustees may not legally consent) and subject to the provision s of the DD LLC Voting Trust Agreement, to receive distributions on the Dan Duncan LLC membership interests. Except as otherwise provided in the DD LLC Voting Trust Agreement, all actions taken by the DD LLC Trustees are by majority vote.

The DD LLC Trustees serve in such capacity without compensation, but they are entitled to incur reasonable charges and expenses deemed necessary and proper for administering the DD LLC Voting Trust Agreement and to reimbursement and indemnification.

The DD LLC Voting Trust Agreement will terminate when (i) the descendants of Mr. Duncan, and entities directly or indirectly controlled by or held for the benefit of any such descendant, no longer own any capital stock of EPCO (as defined below); or (ii) upon such earlier date designated by the DD LLC Trustees by an instrument in writing delivered to the member party to the DD LLC Voting Trust Agreement.

On April 27, 2010, the independent co-executors for the estate of Mr. Duncan were appointed by the probate court. The independent co-executors are Mr. Bachmann, Dr. Cunningham and Ms. Williams, who are the same persons as the current DD LLC Trustees and voting trustees under a separate voting trust agreement relating to a majority of EPCO's outstanding shares with voting rights (as more fully described below).

References to "EPCO" mean Enterprise Products Company (formerly EPCO, Inc.) and its privately held affiliates. Prior to Mr. Duncan's death, we, Enterprise Products Partners, EPO, DEP GP, EPGP, Holdings and EPE Holdings were affiliates under the common control of Mr. Duncan, since he was the controlling shareholder of EPCO and the controlling member of Dan Duncan LLC. A majority of the outstanding voting capital stock of EPCO is owned of record by a voting trust formed on April 26, 2006, pursuant to the EPCO Inc. Voting Trust Agreement (the "EPCO Voting Trust Agreement"), among EPCO and Mr. Duncan (as the record owner of a majority of the outstanding voting capital stock of EPCO immediately prior to the entering into of the EPCO Voting T rust Agreement and as the initial sole voting trustee).

Immediately upon Mr. Duncan's death, voting and dispositive control of such majority of the outstanding voting capital stock of EPCO was transferred pursuant to the EPCO Voting Trust Agreement to three voting trustees (the "EPCO Trustees"). The current EPCO Trustees are: (i) Ms. Williams, who serves as Chairman of EPCO; (ii) Dr. Cunningham, who serves as a Vice Chairman of EPCO; and (iii) Mr. Bachmann, who serves as the President, CEO and Chief Legal Officer of EPCO. Ms. Williams, Dr. Cunningham and Mr. Bachmann are also currently directors of EPCO. The current EPCO Trustees are the same as the current DD LLC Trustees, which control Dan Duncan LLC. The current EPCO Trustees are also the same persons as the individuals appointed on April 27, 2010 as the independent co-executors of the estate of Mr. Duncan.

References to the "DEP I Midstream Businesses" collectively refer to (i) Mont Belvieu Caverns, LLC ("Mont Belvieu Caverns"); (ii) Acadian Gas, LLC ("Acadian Gas"); (iii) Enterprise Lou-Tex Propylene Pipeline L.P. ("Lou-Tex Propylene"), including its general partner; (iv) Sabine Propylene Pipeline L.P. ("Sabine Propylene"), including its general partner; and (v) South Texas NGL Pipelines, LLC ("South Texas NGL"). We acquired controlling ownership interests in the DEP I Midstream Businesses from EPO effective February 1, 2007 in a drop down transaction (the "DEP I drop down") in connection with our initial public offering.

References to the "DEP II Midstream Businesses" collectively refer to (i) Enterprise GC, L.P. ("Enterprise GC"); (ii) Enterprise Intrastate L.P. ("Enterprise Intrastate"); and (iii) Enterprise Texas Pipeline LLC ("Enterprise Texas"). We acquired controlling ownership interests in the DEP II Midstream Businesses from EPO on December 8, 2008 in a drop down transaction (the "DEP II drop down"). Our ownership interests in the DEP II Midstream Businesses are held by Enterprise Holding III, LLC, which is a wholly owned subsidiary of DEP OLP. Ownership interests in the DEP II Midstream Businesses that were retained by EPO are held by its wholly owned subsidiary, Enterprise GTM Holdings L.P.

References to "Evangeline" mean our aggregate 49.51% equity method investment in Evangeline Gas Pipeline Company, L.P. ("EGP") and Evangeline Gas Corp ("EGC").

References to "Energy Transfer Equity" mean the business and operations of Energy Transfer Equity, L.P. and its consolidated subsidiaries, which include Energy Transfer Partners, L.P. ("ETP") and, effective May 26, 2010, Regency Energy Partners LP ("RGNC"). Energy Transfer Equity is a publicly traded Delaware limited partnership, the common units of which are listed on the NYSE under the ticker symbol "ETE." ETP is a publicly traded Delaware limited partnership, the common units of which are listed on the NYSE under the ticker symbol "ETP." RGNC is a publicly traded Delaware limited partnership, the common units of which are traded on the NASDAQ stock market under the ticker symbol "RGNC." The general partner of Energy Transfer Equity is LE GP, LLC.

References to the "Employee Partnerships" mean EPE Unit L.P., EPE Unit II, L.P., EPE Unit III, L.P., Enterprise Unit L.P. and EPCO Unit L.P. ("EPCO Unit"), collectively, all of which were privately held affiliates of EPCO. The Employee Partnerships were liquidated in August 2010. See Note 3 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report for additional information.

As generally used in the energy industry and in this discussion, the identified terms have the following meanings:

/d	= per day
Tbtus	= trillion British thermal units
BBtus	= billion British thermal units
MBPD	= thousand barrels per day
MMBbls	= million barrels
MMBtus	= million British thermal units
MMcf	= million cubic feet
Bcf	= billion cubic feet

Cautionary Note Regarding Forward-Looking Statements

This discussion contains various forward-looking statements and information that are based on our beliefs and those of our general partner, as well as assumptions made by us and information currently *available to us. When used in this document, words such as "anticipate," "project," "expect," "plan," "seek," "goal," "estimate," "forecast," "intend," "could," "should," "will," "believe," "may," "potential" and similar expressions and statements regarding our plans and objectives for future operations, are intended to identify forward-looking statements. Although we and our general partner believe that the expectations reflected in such forward-looking statements are reasonable, neither we nor our general partner can give any assurances that such expectations will prove to be correct. Forward-looking statements are subject to a variety of risks, uncertainties and assumptions as described in more d etail under Item 1A "Risk Factors" included in our annual report on Form 10-K for the year ended December 31, 2009, as filed on March 1, 2010 and in Part II, Item 1A of this quarterly report on Form 10-Q. If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, our actual results may vary materially from those anticipated, estimated, projected or expected. You should not put undue reliance on any forward-looking statements. The forward-looking statements in this quarterly report speak only as of the date hereof. Except as required by federal and state securities laws, we undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or any other reason.*

Overview of Business

We are a publicly traded Delaware limited partnership, the common units of which are listed on the NYSE under the ticker symbol "DEP." We were formed by EPO in September 2006 and completed our initial public offering of common units in February 2007. Our business purpose is to acquire, own and operate a diversified portfolio of midstream energy assets and to support the growth objectives of EPO and other affiliates of EPCO that are under common control. We are engaged in the business of (i) NGL transportation, fractionation and marketing; (ii) storage of NGL and petrochemical products; (iii) transportation of petrochemical products and (iv) the gathering, transportation, marketing and storage of natural gas. Our assets, located primarily in Texas and Louisiana, include: 11,000 mi les of natural gas, NGL and petrochemical pipelines; two NGL fractionation facilities; approximately 18 MMBbls of leased NGL storage capacity; 8.1 Bcf of leased natural gas storage capacity; and 34 underground salt dome caverns with over 100 MMBbls of NGL storage capacity. Our assets are integral to EPO's midstream energy operations and are located near significant natural gas production basins such as the Eagle Ford Shale, Barnett Shale and Haynesville Shale plays.

We have three reportable business segments: (i) NGL Pipelines & Services; (ii) Natural Gas Pipelines & Services; and (iii) Petrochemical Services. Our business segments reflect the manner in which these businesses are managed and reviewed by the CEO of our general partner. See Note 12 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report for additional information regarding our business segments.

We are owned 99.3% by our limited partners and 0.7% by our general partner, DEP GP. At September 30, 2010, EPO owned approximately 58.5% of our limited partner interests and 100% of DEP GP. We, DEP GP, EPO, Enterprise Products Partners, Holdings, EPE Holdings, EPCO and Dan Duncan LLC are affiliates and under the collective common control of the DD LLC Trustees and EPCO Trustees. We have no employees. All of our operating functions and general and administrative support services are provided by employees of EPCO pursuant to an administrative services agreement (the "ASA") or by other service providers.

Our relationship with EPO is one of our principal business advantages. Our assets connect to various midstream energy assets of EPO and form integral links within EPO's value chain of assets. We believe that the operational significance of our assets to EPO, as well as the alignment of our respective economic interests in these assets, will result in a collaborative effort between us and EPO to promote the operational efficiency of our assets and maximize their value. See Note 13 of Item 1 of this quarterly report on Form 10-Q for additional information regarding our relationship with Enterprise Products Partners, EPO and EPCO.

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DEP I Drop Down

Effective February 1, 2007, EPO contributed to us a 66% controlling equity interest in each of the DEP I Midstream Businesses in a drop down transaction. EPO retained the remaining 34% noncontrolling equity interest in each of these businesses. As consideration for these equity interests, we paid $459.5 million in cash and issued 5,351,571 common units to EPO. The cash portion of this consideration was financed with $198.9 million in borrowings under our $300 million unsecured revolving credit facility (the "Revolving Credit Facility") and $260.6 million of the $290.5 million of net proceeds from our initial public offering. The following is a brief description of the assets and operations of the DEP I Midstream Businesses:

§ Mont Belvieu Caverns owns 34 underground salt dome storage caverns located in Mont Belvieu, Texas, having an NGL and related product storage capacity of approximately 100 MMBbls, and a brine system with approximately 20 MMBbls of above ground storage capacity and related brine production wells.

§ Acadian Gas is engaged in the gathering, transportation, storage and marketing of natural gas in south Louisiana, utilizing over 1,000 miles of pipelines having an aggregate throughput capacity of 1.0 Bcf/d. Acadian Gas also owns a 49.51% equity interest in Evangeline, which owns a 27-mile natural gas pipeline located in southeast Louisiana.

In October 2009, we and EPO announced plans for our jointly owned Acadian Gas system to extend its Louisiana intrastate natural gas pipeline system into northwest Louisiana to provide producers in the Haynesville Shale production area with access to additional markets in south Louisiana and connections to nine third-party major interstate natural gas pipelines. This expansion capital project is referred to as the "Haynesville Extension" of the Acadian Gas system. As currently designed, the Haynesville Extension will have the potential capacity to transport up to 2.1 Bcf/d of natural gas from the Haynesville area through a 249-mile pipeline that will connect with our existing Acadian Gas system. The Haynesville Extension is expected to be in service during the third quarter of 2011.

The total expected cost of the Haynesville Extension is approximately $1.56 billion (including capitalized interest). In June 2010, we agreed to fund 66% of the Haynesville Extension project costs and EPO will fund the remaining 34% of such expenditures; therefore, we estimate that our share of such costs will approximate $1.03 billion. In order to address our funding requirements under the Haynesville Extension project, we entered into new long-term senior unsecured credit facilities having an aggregate borrowing capacity of $1.25 billion in October 2010.

For information regarding our agreements with EPO related to the Haynesville Extension, see Note 13 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report. For information regarding our $1.25 billion credit facilities, see "Significant Recent Developments - $1.25 Billion Senior Unsecured Credit Facilities" under this Item 2.

§ Lou-Tex Propylene owns a 263-mile pipeline used to transport chemical-grade propylene from Sorrento, Louisiana to Mont Belvieu, Texas.

§ Sabine Propylene owns a 21-mile pipeline used to transport polymer-grade propylene from Port Arthur, Texas to a pipeline interconnect in Cameron Parish, Louisiana.

§ South Texas NGL owns a 297-mile pipeline system used to transport NGLs from our Shoup and Armstrong NGL fractionation facilities in south Texas to Mont Belvieu, Texas.

DEP II Drop Down

On December 8, 2008, EPO contributed to us the following controlling equity interests in a second drop down transaction: (i) a 66% voting general partner interest in Enterprise GC, (ii) a 51% voting general partner interest in Enterprise Intrastate and (iii) a 51% voting membership interest in Enterprise Texas. As consideration for these equity interests, we paid $280.5 million in cash and issued 37,333,887 Class B units to EPO (which automatically converted on a one-for-one basis to common units in February 2009). The cash portion of this consideration was financed with $280.0 million in borrowings under our $300.0 million senior unsecured term loan agreement (the “Term Loan Agreement”) and $0.5 million of net proceeds from an equity offering to EPO.□ 60; The market value of the Class B units at the time of issuance was approximately $449.5 million. The following is a brief description of the assets and operations of the DEP II Midstream Businesses:

§ Enterprise GC operates and owns: (i) two NGL fractionation facilities, the Shoup and Armstrong facilities, located in south Texas; (ii) a 1,020-mile NGL pipeline system located in south Texas; and (iii) 1,108 miles of natural gas gathering pipelines located in south and west Texas. Enterprise GC’s natural gas gathering pipelines include: (i) the 258-mile Big Thicket Gathering System located in southeast Texas; (ii) the 660-mile Waha system located in the Permian Basin of west Texas; and (iii) the 190-mile TPC Offshore gathering system located in south Texas.

§ Enterprise Intrastate operates and owns an undivided 50% interest in the assets comprising the 641-mile Channel natural gas pipeline, which extends from the Agua Dulce Hub in south Texas to Sabine, Texas located on the Texas/Louisiana border.

§ Enterprise Texas owns the 6,560-mile Enterprise Texas natural gas pipeline system, which includes the Sherman Extension and Trinity River Lateral pipelines, and leases the Wilson natural gas storage facility. The Enterprise Texas system, along with the Waha, TPC Offshore and Channel pipeline systems, comprise our Texas Intrastate System.

In July 2010, we completed and placed into service the final segment of our Trinity River Lateral natural gas pipeline, which is a component of our Texas Intrastate System. In total, the Trinity River Lateral pipeline extends approximately 40 miles from the Trinity River Basin north of Arlington, Texas to an interconnect near Justin, Texas with our Sherman Extension pipeline. The Trinity River Lateral provides producers in Tarrant and Denton Counties in north Texas with up to 1 Bcf/d of production takeaway capacity.

Our Texas Intrastate System is strategically located to benefit from increasing natural gas production from the Eagle Ford Shale basin located in south Texas. We are in the process of expanding the system’s natural gas gathering and transportation capabilities as well as increasing our storage capacity at Wilson to handle the expected increase in production volumes. EPO is funding 100% of the growth capital spending associated with these expansion projects.

To the extent that the DEP II Midstream Businesses collectively generate cash sufficient to pay distributions to EPO and us, such cash will be distributed first to us (based on an initial defined investment of $730.0 million) and then to EPO in amounts sufficient to generate an aggregate annualized return on their respective investments. From December 8, 2008 through December 31, 2009, the annualized return was 11.85%. Effective January 1, 2010, the annualized return increased by 2.0% to 12.087%. Distributions in excess of these amounts will be distributed 98% to EPO and 2% to us. Income and loss of the DEP II Midstream Businesses are first allocated to EPO and us based on each entity’s percentage interest of 77.4% and 22.6%, respectively , and then in a manner that in part follows the cash distributions.

For detailed information regarding EPO’s noncontrolling interest in the DEP I and DEP II Midstream Businesses, see Note 11 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report.

Our results of operations for the three and nine months ended September 30, 2010 are not necessarily indicative of results expected for the full year.

Supplemental Selected Financial Information of Duncan Energy Partners L.P.

We are providing the following selected financial information to assist investors and other users of our financial statements in understanding the principal sources and uses of cash flows of Duncan Energy Partners L.P. On a standalone basis, Duncan Energy Partners L.P. has no operations apart from its investing activities and indirectly overseeing the management of the DEP I and DEP II Midstream Businesses.

The primary sources of cash flow for Duncan Energy Partners L.P. on a standalone basis are the cash distributions it receives from the DEP I and DEP II Midstream Businesses. The primary cash requirements of Duncan Energy Partners on a standalone basis are for general and administrative costs, debt service, investments in subsidiaries and distributions to partners. The amount of cash distributions that Duncan Energy Partners L.P. is able to pay its unitholders may fluctuate based on the level of distributions it receives from its operating subsidiaries. Factors such as capital contributions, debt service requirements, general and administrative costs, reserves for future distributions and other cash reserves established by the board of directors of our gen eral partner may also affect the distributions Duncan Energy Partners L.P. makes to its unitholders.

For purposes of this presentation, we have provided information pertaining to the DEP I Midstream Businesses apart from those of the DEP II Midstream Businesses.

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2010	2009	2010	2009
Selected income statement information:				
Equity in income - DEP I Midstream Businesses	$ 12.1	$ 12.4	$ 34.1	$ 32.2
Equity in income - DEP II Midstream Businesses	$ 11.6	$ 15.7	$ 41.9	$ 46.4
General and administrative costs	$ 0.1	$ 0.1	$ 1.6	$ 0.3
Interest expense	$ 3.0	$ 3.2	$ 9.3	$ 10.4
Net income attributable to Duncan Energy Partners L.P.	$ 20.6	$ 24.8	$ 65.1	$ 67.9
Selected balance sheet information at each period end:				
Investments in DEP I Midstream Businesses	$ 718.0	$ 506.6	$ 718.0	$ 506.6
Investments in DEP II Midstream Businesses	$ 685.5	$ 717.6	$ 685.5	$ 717.6
Total debt principal outstanding	$ 654.8	$ 462.8	$ 654.8	$ 462.8
Partners' equity	$ 760.0	$ 762.7	$ 760.0	$ 762.7

The following table presents the amount of distributions paid by the DEP I and DEP II Midstream Businesses to Duncan Energy Partners L.P. with respect to each period:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2010	2009	2010	2009
Distributions paid to Duncan Energy Partners L.P. with respect to each period from:				
DEP I Midstream Businesses	$ 13.6	$ 12.5	$ 40.6	$ 40.1
DEP II Midstream Businesses	$ 22.1	$ 21.6	$ 66.2	$ 64.9

To the extent that the DEP II Midstream Businesses collectively generate cash sufficient to pay distributions to EPO and us, such cash will be distributed first to us (the "Tier I distribution," based on our $730.0 million aggregate investment) and then to EPO (the "Tier II distribution"), in amounts sufficient to generate an annualized return to both owners based on their respective investments. Distributions in excess of these amounts (the "Tier III distributions") will be distributed 98% to EPO and 2% to us.

The annualized return rate from December 8, 2008 through December 31, 2009 was 11.85%, and was determined by EPO and us based on our estimated weighted-average cost of capital at December 8, 2008, plus 1.0%. The annualized return rate increases by 2.0% on January 1 of each year. As a result, the annualized return rate for fiscal 2010 is 12.087%. If we participate in an expansion capital project involving the DEP II Midstream Businesses, we may request an incremental adjustment to the then-applicable annualized return rate to reflect our weighted-average cost of capital associated with such contribution.

The annualized return rate is applied to each party's aggregate investment (or "Distribution Base") in the DEP II Midstream Businesses. To the extent that we and/or EPO make capital contributions to fund expansion capital projects involving the DEP II Midstream Businesses, the Distribution Base of the contributing member will be increased by that member's capital contribution at the time such contribution is made. At December 8, 2008 and September 30, 2010, our Distribution Base was $730.0 million. EPO's Distribution Base was $452.1 million, $817.9 million and $1.05 billion at December 8, 2008, December 31, 2009 and September 30, 2010, respectively. The increase in EPO's Distribution Base is the result of its funding 100% of the expansion capital projects of the DEP II Midstream Businesses since December 8, 2008. For the nine months ended September 30, 2010, EPO funded $228.3 million of expansion capital spending of the DEP II Midstream Businesses. This spending primarily relates to natural gas pipeline projects in the Barnett Shale (e.g., completion of the Trinity River Lateral in July 2010) and ongoing expansions of our pipeline network in the Eagle Ford Shale region. We have not yet participated in the expansion capital project spending of the DEP II Midstream Businesses, although we may elect to invest in existing or future expansion projects at a later date.

The DEP II Midstream Businesses distributed an aggregate of $35.6 million and $29.4 million for the three months ended September 30, 2010 and 2009, respectively. For the nine months ended September 30, 2010 and 2009, the DEP II Midstream Businesses distributed an aggregate of $97.6 million and $83.6 million, respectively. Of these amounts, EPO received $13.5 million and $7.8 million for the three months ended September 30, 2010 and 2009, respectively, and $31.4 million and $18.7 million for the nine months ended September 30, 2010 and 2009, respectively.

The $22.1 million and $66.2 million received by us from the DEP II Midstream Businesses with respect to the three and nine months ended September 30, 2010, respectively, represent approximately one-quarter and three-quarters, respectively, of the annualized return rate for 2010 of 12.087% multiplied by our Distribution Base of $730.0 million. As a result, we received our expected Tier I distributions for the periods indicated. Based on EPO's Distribution Base, it was entitled to $31.6 million and $87.5 million of Tier II distributions for the three and nine months ended September 30, 2010, respectively, of which it received $13.5 million and $31.4 million, respectively. No Tier III distributions were paid by the DEP II Midstream Businesses with resp ect to the nine months ended September 30, 2010.

Net income (or loss) of the DEP II Midstream Businesses is first allocated to us and EPO based on each entity's percentage interest of 22.6% and 77.4%, respectively, and then in a manner that in part follows the cash distributions paid by (or contributions made to) each of the DEP II Midstream Business. Under our income sharing arrangement with EPO, we are allocated additional income (in excess of our percentage interest) to the extent that the cash distributions we receive (or contributions made) exceed the amount we would have been entitled to receive (or required to fund) based solely on our percentage interest. This additional earnings allocation to us reduces the amount of income allocated to EPO by an equal amount and may result in EPO being allocated a loss when we are allocated income. Our participation in the expected future increase in cash flow from such projects is limited (beyond our annualized return amount) to 2% of such upside, with EPO receiving 98% of the benefit.

For information regarding the non-cash depreciation, amortization and accretion amounts of the DEP I and DEP II Midstream Businesses on a 100% basis, see Note 17 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report.

Significant Recent Developments

The following information highlights specified significant developments since January 1, 2010 through the date of this filing, including (i) information relevant to an understanding of our financial condition, changes in financial condition or results of operations, and (ii) certain unusual or infrequent events or transactions and known trends or uncertainties that have had or that we reasonably expect may have a material impact on our revenues or income from continuing operations. For a discussion of recent regulatory matters, see Part II – Item 1A "Risk Factors".

$1.25 Billion Senior Unsecured Credit Facilities

On October 25, 2010, we entered into new long-term variable rate senior unsecured credit facilities having an aggregate borrowing capacity of $1.25 billion. The new credit facilities mature in October 2013 and consist of: (i) an $850.0 million multi-year revolving credit facility (the "DEP Multi-Year Revolving Credit Facility") and (ii) a $400.0 million term loan facility (the "$400 Million Term Loan Facility"). At closing, we borrowed the full amount available under the $400 Million Term Loan Facility to repay amounts outstanding under our Revolving Credit Facility and the Loan Agreement with EPO. Upon repayment, our existing Revolving Credit Facility and the Loan Agreement with EPO were terminated. Our existing $282.3 million Term Loan Agreement remains in place and is scheduled to mature in December 2011.

We entered into these new credit agreements primarily to address our funding requirements under the Haynesville Extension project. See "Overview of Business – DEP I Drop Down" under this Item 2 for additional information regarding our Haynesville Extension project. Variable interest rates charged under the new credit facilities are based on the London InterBank Offered Rate (or "LIBOR") or a base rate, both as defined in the agreement.

Expansion of Shoup and Armstrong Fractionation Facilities

In May 2010, we and Enterprise Products Partners announced plans to expand our jointly owned Shoup and Armstrong fractionation facilities (both of which are part of the DEP II Midstream Businesses). This expansion project will provide us with the ability to accommodate increased NGL volumes due to increased natural gas production from the Eagle Ford natural gas supply basin. On June 27, 2010, we completed the modifications to the Shoup facility, which increased its NGL fractionation capacity to 77 MBPD. Modifications to the infrastructure at the Armstrong facility are planned to increase capacity to more than 20 MBPD and is expected to be completed in the fourth quarter of 2010. In addition to the increased NGL volumes, the planned upgrades at the Armstrong facility would allow it to process the more liquid-rich natural gas supply that is found in the Eagle Ford natural gas supply basin. We are not contributing capital to fund this expansion; EPO is contributing 100% of the associated expansion costs.

Registration Statements

In February 2010, we filed a registration statement with the Securities Exchange Commission ("SEC") authorizing the issuance of up to an aggregate 1,000,000 common units in connection with an employee unit purchase plan ("EUPP") and a long-term incentive plan that became effective on February 11, 2010.

Results of Operations

We have three reportable business segments: Natural Gas Pipelines & Services; NGL Pipelines & Services and Petrochemical Services. Our business segments are generally organized and managed according to the type of services rendered (or technologies employed) and products produced and/or sold.

We evaluate segment performance based on the non-GAAP financial measure of gross operating margin. Gross operating margin (either in total or by individual segment) is an important performance measure of the core profitability of our operations. This measure forms the basis of our internal financial reporting and is used by management in deciding how to allocate capital resources among business segments. We believe that investors benefit from having access to the same financial measures that our management uses in evaluating segment results. The GAAP financial measure most directly comparable to total segment gross operating margin is operating income. Our non-GAAP financial measure of total segment gross operating margin should not be considered as an alternative to GAAP operating income.

Selected Volumetric Data

The following table presents significant throughput and fractionation volumes for the periods indicated. These statistics are presented in total for each asset (or asset group) irrespective of ownership interest (i.e., on a 100% basis), with the exception of pipeline throughput volumes for Evangeline (a component of the Acadian Gas System). We report volumes for Evangeline on a net basis to our ownership interest.

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2010	2009	2010	2009
Natural Gas Pipelines & Services:				
Natural gas throughput volumes (BBtus/d)				
Texas Intrastate System	4,082	3,857	3,896	3,989
Acadian Gas System:				
Transportation volumes	445	453	435	427
Sales volumes (1)	371	383	343	330
Total natural gas throughput volumes	4,898	4,693	4,674	4,746
NGL Pipelines & Services:				
NGL throughput volumes (MBPD)				
South Texas NGL System - Pipelines	125	105	119	109
NGL fractionation volumes (MBPD)				
South Texas NGL System - Fractionators	80	74	76	77
Petrochemical Services:				
Propylene throughput volumes (MBPD)				
Lou-Tex Propylene Pipeline	27	26	24	19
Sabine Propylene Pipeline	13	9	12	9
Total propylene throughput volumes	40	35	36	28

(1) Includes average net sales volumes for Evangeline of 66.1 BBtus/d and 71.3 BBtus/d for the three months ended September 30, 2010 and 2009, respectively. For the nine months ended September 30, 2010 and 2009, net sales volumes for Evangeline were 49.6 BBtus/d and 53.8 BBtus/d, respectively.

Comparison of Consolidated Results of Operations

The following table summarizes key components of our consolidated income statement for the periods indicated (dollars in millions):

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2010	2009	2010	2009
Revenues	$ 283.7	$ 244.6	$ 839.5	$ 728.1
Operating costs and expenses	268.5	220.8	780.8	675.7
General and administrative costs	6.4	3.2	16.1	8.8
Equity in income of Evangeline	0.3	0.5	0.5	1.0
Operating income	9.1	21.1	43.1	44.6
Interest expense	3.0	3.4	9.3	10.6
Benefit from (provision for) income taxes	(0.5)	0.1	(0.7)	(0.8)
Net income	5.7	17.8	33.2	33.3
Net loss (income) attributable to noncontrolling interest:				
DEP I Midstream Businesses – Parent	(7.4)	(5.7)	(19.9)	(10.3)
DEP II Midstream Businesses – Parent	22.3	12.7	51.8	44.9
Net income attributable to Duncan Energy Partners L.P.	20.6	24.8	65.1	67.9

For information regarding noncontrolling interest, see Note 11 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report.

Our gross operating margin by business segment and in total is presented as follows for the periods indicated (dollars in millions):

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2010	2009	2010	2009
Natural Gas Pipelines & Services	$ 46.3	$ 40.5	$ 125.9	$ 109.5
NGL Pipelines & Services	25.5	28.3	84.0	73.3
Petrochemical Services	2.6	2.8	7.8	7.9
Total segment gross operating margin	$ 74.4	$ 71.6	$ 217.7	$ 190.7

For a reconciliation of non-GAAP gross operating margin to GAAP operating income and further to GAAP income before income taxes, see "Other Items – Non-GAAP Reconciliations" within this Item 2. For additional information regarding our business segments, see Note 12 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report.

The following table summarizes each business segment's contribution to revenues (net of eliminations and adjustments) for the periods indicated (dollars in millions):

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2010	2009	2010	2009
Natural Gas Pipelines & Services:				
Sales of natural gas	$ 139.0	$ 113.6	$ 419.6	$ 348.9
Natural gas transportation services	71.8	66.1	210.8	192.5
Natural gas storage services	3.7	4.4	12.2	11.2
Total	214.5	184.1	642.6	552.6
NGL Pipelines & Services:				
Sales of NGLs	10.2	9.4	31.2	24.3
Sales of other products	4.5	2.3	12.7	8.6
NGL and petrochemical storage services	30.8	26.7	86.7	76.4
NGL fractionation services	8.1	7.2	22.2	22.0
NGL transportation services	11.4	10.8	32.2	32.0
Other services	0.5	0.6	1.5	2.0
Total	65.5	57.0	186.5	165.3
Petrochemical Services:				
Propylene transportation services	3.7	3.5	10.4	10.2
Total consolidated revenues	$ 283.7	$ 244.6	$ 839.5	$ 728.1

Comparison of the Three Months Ended September 30, 2010 with the Three Months Ended September 30, 2009

Revenues for the third quarter of 2010 were $283.7 million compared to $244.6 million for the third quarter of 2009. The $39.1 million quarter-to-quarter increase in consolidated revenues is primarily due to higher energy commodity prices during the third quarter of 2010 relative to the third quarter of 2009. This factor accounted for a $28.4 million quarter-to-quarter increase in revenues from the sale of natural gas, NGLs and other products. Revenues from our natural gas transportation and storage services increased $5.0 million quarter-to-quarter primarily due to higher firm capacity reservation fees on the Sherman Extension of our Texas Intrastate System. The Sherman Extension pipeline commenced operations and began earning firm capacity reserva tion fees during August 2009. Collectively, revenues from all other services we provide to customers increased $5.7 million quarter-to-quarter primarily due to higher NGL storage fees and volumes during the third quarter of 2010 compared to the third quarter of 2009.

Operating costs and expenses were $268.5 million for the third quarter of 2010 versus $220.8 million for the third quarter of 2009, a $47.7 million quarter-to-quarter increase. The cost of sales of our natural gas and NGL products increased $29.1 million quarter-to-quarter primarily as a result of higher energy commodity prices. Consolidated operating costs and expenses decreased $1.8 million quarter-to-quarter attributable to operational measurement gains and losses at our Mont Belvieu storage complex. Such gains and losses are subsequently allocated to EPO through noncontrolling interest. Operating costs and expenses for the third quarter of 2010 include $0.4 million of the $2.7 million of total expense related to liquidation of the Employee Partnerships in August 2010. The remaining $2.3 million of expense related to the Employee Partnership liquidations is a component of our general and administrative costs for the third quarter of 2010 (see below). Operating costs and expenses for the third quarter of 2010 also include a $9.1 million non-cash loss for the disposition of a smal l segment of non-strategic pipeline and $6.8 million of accrued expense related to litigation for a contractual dispute. Collectively, the remainder of our consolidated operating costs and expenses increased $4.1 million quarter-to-quarter primarily due to an increase in depreciation expense associated with recently completed assets and higher repair and maintenance expenses at certain of our facilities.

Changes in our revenues and operating costs and expenses quarter-to-quarter are due in part to changes in energy commodity prices. In general, higher energy commodity prices result in an increase in our revenues attributable to the sale of natural gas and NGLs; however, these higher commodity prices also increase the associated cost of sales as purchase prices rise. The market price of natural gas (as measured at Henry Hub in Louisiana) averaged $4.38 per MMBtu during the third quarter of 2010 versus $3.39 per MMBtu during the third quarter of 2009. The weighted-average indicative market price for NGLs was $1.04 per gallon during the third quarter of 2010 versus $0.88 per gallon during the third quarter of 2009. Our determination of the weighte d-average indicative market price for NGLs is based on U.S. Gulf Coast prices for such products at Mont Belvieu, Texas, which is the primary industry hub for domestic NGL production.

General and administrative costs increased to $6.4 million for the third quarter of 2010 from $3.2 million for the third quarter of 2009. The $3.2 million quarter-to-quarter increase in general and administrative costs is primarily due to $2.3 million of charges related to the Employee Partnership liquidations. Equity in income of Evangeline decreased $0.2 million quarter-to-quarter.

Operating income for the third quarter of 2010 was $9.1 million compared to $21.1 million for the third quarter of 2009. Collectively, the changes in revenues, costs and expenses and equity in income of Evangeline described above resulted in the $12.0 million quarter-to-quarter decrease in operating income.

Interest expense decreased $0.4 million quarter-to-quarter primarily due to an increase in the amount of interest capitalized as a result of higher spending on our growth capital projects during the third quarter of 2010 compared to the third quarter of 2009. Income tax expense accruals for the Texas Margin Tax increased $0.6 million quarter-to-quarter.

As a result of items noted in the previous paragraphs, net income decreased $12.1 million quarter-to-quarter to $5.7 million for the third quarter of 2010 compared to $17.8 million for the third quarter of 2009.

We account for EPO's share of the net income of the DEP I and DEP II Midstream Businesses as noncontrolling interest, which is an adjustment to net income to arrive at the amount of net income attributable to Duncan Energy Partners L.P. EPO was attributed $7.4 million of the net income of the DEP I Midstream Businesses for the third quarter of 2010 compared to $5.7 million for the third quarter of 2009. The quarter-to-quarter increase in EPO's share of the net income of the DEP I Midstream Businesses is primarily due to changes in the amount of operational measurement gains recorded by Mont Belvieu Caverns (EPO is allocated 100% of such gains). EPO was attributed losses of $22.3 million and $12.7 million in connection with its ownership intere sts in the DEP II Midstream Businesses for the third quarters of 2010 and 2009, respectively. Collectively, EPO's share of the net losses of the DEP II Midstream Businesses for the third quarter of 2010 includes $13.2 million of expenses resulting from the disposition of a pipeline segment, litigation for a contractual dispute and liquidation of the Employee Partnerships. See Note 11 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report for information regarding our determination of net income attributable to EPO's noncontrolling interest.

The following information highlights significant quarter-to-quarter variances in gross operating margin by business segment:

Natural Gas Pipelines & Services. Gross operating margin from this business segment was $46.3 million for the third quarter of 2010 compared to $40.5 million for the third quarter of 2009, a $5.8 million quarter-to-quarter increase. Total natural gas throughput volumes were 4.9 Tbtus/d for the third quarter of 2010 compared to 4.7 Tbtus/d for the third quarter of 2009. Gross operating margin from our Texas Intrastate System increased $8.2 million quarter-to-quarter primarily due to higher firm capacity reservation fee revenues earned by the Sherman Extension pipeline. Collectively, gross operating margin for the remainder of the businesses within this segme nt decreased $2.4 million quarter-to-quarter primarily due to lower natural gas sales margins and throughput volumes on our Acadian Gas System.

NGL Pipelines & Services. Gross operating margin from this business segment was $25.5 million for the third quarter of 2010 compared to $28.3 million for the third quarter of 2009, a $2.8 million quarter-to-quarter decrease. Mont Belvieu Caverns' recorded operational measurement gains of $2.6 million for the third quarter of 2010 compared to gains of $0.8 million for the third quarter of 2009. Segment gross operating margin decreased $4.6 million quarter-to-quarter excluding Mont Belvieu Caverns' operational measurement gains. The third quarter of 2010 includes a $6.8 million accrued expense related to litigation for a contractual disp ute involving our South Texas NGL pipeline system that began prior to its acquisition from a third party in September 2004.

Collectively, gross operating margin for the remainder of this segment increased $2.2 million primarily due to higher storage fees and volumes at our Mont Belvieu storage complex. In November 2010, we expect to complete the conversion of the first storage cavern at our Mont Belvieu complex from NGL service to refined products service. We expect to earn higher storage fees from caverns placed in refined products service.

Petrochemical Services. Gross operating margin from this business segment was $2.6 million for the third quarter of 2010 compared to $2.8 million for the third quarter of 2009, a $0.2 million quarter-to-quarter decrease. Petrochemical transportation volumes increased to 40 MBPD during the third quarter of 2010 from 35 MBPD during the third quarter of 2009. Pipeline transportation revenues increased $0.2 million quarter-to-quarter due to higher transportation volumes, primarily on our Lou-Tex Propylene Pipeline. Segment costs and expense increased $0.4 million quarter-to-quarter primarily due to higher pipeline repair and maintenance expenses on our Lou-Tex Prop ylene Pipeline.

Comparison of the Nine Months Ended September 30, 2010 with the Nine Months Ended September 30, 2009

Revenues for the first nine months of 2010 were $839.5 million compared to $728.1 million for the first nine months of 2009. The $111.4 million period-to-period increase in consolidated revenues is primarily due to higher energy commodity prices and sales volumes during the first nine months of 2010 relative to the first nine months of 2009. These factors accounted for an $81.7 million period-to-period increase in revenues from the sale of natural gas, NGLs and other products. Natural gas transportation revenues increased $36.4 million period-to-period due to higher firm capacity reservation fees primarily on the Sherman Extension of our Texas Intrastate System. Revenues from the remainder of our natural gas transportation and storage services decreased $17.1 million period-to-period primari ly due to lower throughput volumes on other segments of the Texas Intrastate System. Collectively, revenues from all other services we provide to customers increased $10.4 million period-to-period primarily due to higher NGL storage volumes and fees during the first nine months of 2010 compared to the first nine months of 2009.

Operating costs and expenses were $780.8 million for the first nine months of 2010 compared to $675.7 million for the first nine months of 2009, a $105.1 million period-to-period increase. The cost of sales of our natural gas and NGL products increased $79.2 million period-to-period primarily as a result of higher energy commodity prices and sales volumes. Consolidated operating costs and expenses for the first nine months of 2010 include an aggregate $15.9 million of charges for the disposition of a small section of non-strategic pipeline and accrued expense related to litigation for a contractual dispute. Operating costs and expenses for the first nine months of 2010 also include $0.4 million of expense related to the Employee Partnership liquidations and asset impairment charges of $1.5 million. Consolidated operating costs and expenses decreased $8.8 million period-to-period attributable to operational measurement gains and losses at our Mont Belvieu storage complex. Collectively, the remainder of our consolidated operating costs and expenses increased $16.9 million period-to-period primarily due to higher expenses for depreciation and charges related to the abandonment of certain pipeline laterals on the TPC Offshore gathering system.

Changes in our revenues and operating costs and expenses period-to-period are explained in part by changes in energy commodity prices. The Henry Hub market price of natural gas averaged $4.59 per MMBtu during the first nine months of 2010 versus $3.93 per MMBtu during the first nine months of 2009. The weighted-average indicative market price for NGLs was $1.13 per gallon during the first nine months of 2010 versus $0.77 per gallon during the first nine months of 2009.

General and administrative costs were $16.1 million for the first nine months of 2010 compared to $8.8 million for the first nine months of 2009. The $7.3 million period-to-period increase in general and administrative costs is primarily due to legal expenses and other professional services related to our Haynesville Extension project of $0.7 million and $5.1 million of higher employee compensation costs, including $2.3 million of expense related to the Employee Partnership liquidations. Equity in income of Evangeline decreased $0.5 million period-to-period.

Operating income for the first nine months of 2010 was $43.1 million compared to $44.6 million for the first nine months of 2009. Collectively, the changes in revenues, costs and expenses and equity in income of Evangeline described above resulted in the $1.5 million period-to-period decrease in operating income.

Interest expense decreased $1.3 million period-to-period primarily due to an increase in the amount of interest capitalized as a result of higher spending on our growth capital projects during the first nine months of 2010 compared to the first nine months of 2009. Income tax expense accruals for the Texas Margin Tax decreased $0.1 million period-to-period.

As a result of items noted in the previous paragraphs, net income decreased $0.1 million period-to-period to $33.2 million for the first nine months of 2010 compared to $33.3 million for the first nine months of 2009.

EPO was attributed $19.9 million of the net income of the DEP I Midstream Businesses for the first nine months of 2010 compared to $10.3 million for the first nine months of 2009. The period-to-period increase in EPO's share of the net income of the DEP I Midstream Businesses is primarily due to changes in the amount of operational measurement gains and losses recorded by Mont Belvieu Caverns (EPO is allocated 100% of such gains and losses). EPO was attributed losses of $51.8 million and $44.9 million in connection with its ownership interests in the DEP II Midstream Businesses for the first nine months of 2010 and 2009, respectively. The DEP II Midstream Business generated a net loss of $9.9 million for the nine months ended September 30, 2010 comp ared to a net income of $1.9 million for the comparable 2009 period. See Note 11 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report for information regarding our determination of net income attributable to EPO's noncontrolling interest.

The following information highlights significant period-to-period variances in gross operating margin by business segment:

Natural Gas Pipelines & Services. Gross operating margin from this business segment was $125.9 million for the first nine months of 2010 compared to $109.5 million for the first nine months of 2009, a $16.4 million period-to-period increase. Total natural gas throughput volumes were 4.7 Tbtus/d for the first nine months of 2010 and 2009. Gross operating margin from our Texas Intrastate System increased $18.5 million period-to-period. A $36.4 million period-to-period increase in firm capacity reservation fee revenues on the Texas Intrastate System was partially offset by the effects of lower throughput volumes on other segments of the Texas Intrastate System. Collectively, gross operating margin for the remainder of the businesses within this segment decreased $2.1 million period-to-period primarily due to lower natural gas sales margins on our Acadian Gas System.

NGL Pipelines & Services. Gross operating margin from this business segment was $84.0 million for the first nine months of 2010 compared to $73.3 million for the first nine months of 2009, a $10.7 million period-to-period increase. Mont Belvieu Caverns' recorded operational measurement gains of $7.0 million for the first nine months of 2010 compared to operational measurement losses of $1.8 million for the first nine months of 2009. Segment gross operating margin increased $1.9 million period-to-period, excluding operational measurement gains and losses. The first nine months of 2010 include a $6.8 million accrued expense related to litigation for a c ontractual dispute involving our South Texas NGL pipeline system that began prior to its acquisition from a third party in September 2004. Collectively, gross operating margin from the remainder of the businesses within this segment increased $8.7 million period-to-period primarily due to higher storage volumes and fees at our Mont Belvieu storage complex.

Petrochemical Services. Gross operating margin from this business segment was $7.8 million for the first nine months of 2010 compared to $7.9 million for the first nine months of 2009, a $0.1 million period-to-period decrease. Petrochemical transportation volumes increased to 36 MBPD during the first nine months of 2010 from 28 MBPD during the first nine months of 2009. A period-to-period increase in gross operating margin from the Lou-Tex Propylene Pipeline as a result of increased throughput volumes was more than offset by lower gross operating margin on the Sabine Propylene Pipeline.

Liquidity and Capital Resources

Our primary cash requirements, in addition to normal operating expenses and debt service, are for working capital, capital expenditures, business combinations and distributions to our partners. We expect to fund our short-term needs for such items as operating expenses and sustaining capital expenditures with operating cash flows and borrowings under our credit facilities. Capital expenditures for long-term needs resulting from business expansion projects and acquisitions, including our share of the Haynesville Extension project described below under "Capital Expenditures," are expected to be funded by a variety of sources (either separately or in combination) including operating cash flows, borrowings under credit facilities, cash contributions from our Parent, the issuance of additional equity and debt securities and proceeds from divestitures of ownership interests in assets to affiliates or third parties. We expect to fund cash distributions to partners primarily with operating cash flows. Our debt service requirements are expected to be funded by operating cash flows and/or refinancing arrangements. It is our belief that we will continue to have adequate liquidity and capital resources to fund future recurring operating and investing activities.

At September 30, 2010, we had approximately $139.1 million of liquidity, which included amounts available under then existing credit agreements, including the $200.0 million Loan Agreement with EPO. Pro forma for the new credit facilities we entered into on October 25, 2010, our consolidated liquidity at September 30, 2010 was approximately $861.6 million. See "Significant Recent Developments - $1.25 Billion Senior Unsecured Credit Facilities" under this Item 2 for additional information regarding the Credit Facilities.

At September 30, 2010, our total debt balance was $654.8 million, which included $247.5 million outstanding under our Revolving Credit Facility, $125.0 million under the Loan Agreement with EPO and $282.3 million under our Term Loan Agreement. Our bank loan agreements require us to maintain certain financial and other customary covenants. We were in compliance with the financial covenants of our loan agreements at September 30, 2010.

As a result of our election to fund 66% of the Haynesville Extension project costs, we entered into a $200 million Loan Agreement with EPO. Our borrowings under this revolving loan agreement were primarily used to fund our share of the costs of this capital project. The Loan Agreement with EPO was terminated on October 25, 2010 and amounts due thereunder were repaid using borrowings under our new $400 Million Term Loan Facility.

Registration Statements

We may issue equity or debt securities to assist in meeting our liquidity and capital spending requirements. We have a universal shelf registration statement on file with the SEC that allows us to issue up to an aggregate $1 billion in debt and equity securities for general partnership purposes. After taking into account previous issuances of securities made under this registration statement, we can issue approximately $856.4 million of additional securities under this registration statement in the future.

We also have a registration statement on file with the SEC authorizing the issuance of up to an aggregate 2,000,000 common units in connection with the distribution reinvestment plan (the "DRIP"). The DRIP gives unitholders of record and beneficial owners of our common units the ability to increase the number of our common units they own through voluntarily reinvesting their quarterly cash distributions into the purchase of additional common units. Plan participants may purchase our common units at a discount ranging from 0% to 5% (currently set at 5%), which will be set from time to time by us. We issued 31,762 common units in connection with the DRIP for the nine months ended September 30, 2010, which generated proceeds of $0.7 million from plan participants.

In February 2010, we filed a registration statement with the SEC authorizing the issuance of up to an aggregate 1,000,000 common units in connection with an employee unit purchase plan and a long-term incentive plan. These plans became effective on February 11, 2010. For the nine months ended September 30, 2010, we issued 6,348 common units in connection with the 2010 Plan and 17,979 common units in connection with the EUPP. The EUPP generated proceeds of $0.5 million from plan participants.

Consolidated Cash Flows from Operating, Investing and Financing Activities

The following table summarizes our consolidated cash flows from operating, investing and financing activities for the periods indicated (dollars in millions). For information regarding the individual components of our cash flow amounts, see the Unaudited Condensed Statements of Consolidated Cash Flows.

	For the Nine Months Ended September 30,	
	2010	**2009**
Net cash flows provided by operating activities	$ 213.0	$ 137.3
Cash used in investing activities	594.9	302.2
Cash provided by financing activities	396.4	183.8

Net cash flows provided by operating activities are largely dependent on earnings from our business activities. As a result, these cash flows are exposed to certain risks. We operate predominantly in the midstream energy industry. We provide services for producers and consumers of natural gas, NGLs and petrochemicals. The products that we fractionate, sell or transport are principally used as fuel for residential, agricultural and commercial heating; as feedstock in petrochemical manufacturing; and in the production of motor gasoline. Reduced demand for our services or products by industrial customers, whether because of a decline in general economic conditions, reduced demand for the end products made with our products, or increased competition from other service providers or pro ducers due to pricing differences or other reasons, could have a negative impact on our earnings and operating cash flows. For a more complete discussion of these and other risk factors pertinent to our business, see "Risk Factors" under Item 1A of our annual report on Form 10-K for the year ended December 31, 2009, as initially filed on March 1, 2010, and also this quarterly report on Form 10-Q.

Our Statements of Consolidated Cash Flows are prepared using the indirect method. The indirect method derives net cash flows from operating activities by adjusting net income to remove (i) the effects of all deferrals of past operating cash receipts and payments, such as changes during the period in inventory, deferred income and similar transactions, (ii) the effects of all accruals of expected future operating cash receipts and cash payments, such as changes during the period in receivables and payables, (iii) other non-cash amounts such as depreciation, amortization, changes in the fair market value of derivative instruments and equity in earnings from Evangeline, and (iv) the effects of all items classified as investing or financing cash flows, such as proceeds from asset sales and related transactions or extinguishment of debt. In general, the net effect of changes in operating accounts results from the timing of cash receipts from sales and cash payments for purchases and other expenses during each period. Increases or decreases in inventory are influenced by the quantity of products held in connection with our marketing activities and changes in energy commodity prices.

Cash used in investing activities primarily represents expenditures for additions to property, plant and equipment. Cash provided by financing activities generally consists of borrowings and repayments of debt, distributions to partners, contributions from and distributions to EPO as noncontrolling interest and proceeds from the issuance of equity securities. Amounts presented in our Statements of Consolidated Cash Flows for borrowings and repayments under debt agreements are influenced by the magnitude of cash receipts and payments under our revolving credit facilities.

The following information highlights the significant period-to-period variances in our consolidated cash flow amounts:

Comparison of Nine Months ended September 30, 2010 with the Nine Months ended September 30, 2009

Operating activities. Net cash flows provided by operating activities were $213.0 million for the nine months ended September 30, 2010 compared to $137.3 million for the nine months ended September 30, 2009. The change in operating cash flow is primarily due to the timing of related cash receipts and disbursements and a $27.0 million increase in period-to-period gross operating margin.

Investing activities. Cash used in investing activities was $594.9 million for the nine months ended September 30, 2010 compared to $302.2 million for the nine months ended September 30, 2009. The $292.7 million increase is primarily due to the following:

§ A $340.4 increase in net capital expenditures as a result of expansion projects such as the Haynesville Extension and those on our Texas Intrastate System.

In June 2010, we entered into the Amended Acadian LLC Agreement with EPO. As a part of this agreement, we and EPO agreed to fund the construction of the Haynesville Extension in accordance with our respective sharing ratios in Acadian Gas (i.e., 66% for us and 34% for EPO). See Note 13 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report for additional information regarding the Amended Acadian LLC Agreement.

§ A $45.6 million cash inflow in January 2010 attributable to EPO's repayment of a temporary cash advance made in December 2009.

Financing activities. Cash provided by financing activities was $396.4 million for the nine months ended September 30, 2010 compared to $183.8 million for the nine months ended September 30, 2009. The period-to-period increase of $212.6 million is primarily due to:

§ Net borrowings under bank credit agreements of $72.5 million compared to net repayments of $21.5 million, an increase of $94.0 million.

§ Borrowings of $125.0 million under the Loan Agreement with EPO.

§ A $14.7 million increase in distributions to our unitholders and general partner due to increases in our quarterly distribution rates.

- § A $38.9 million increase in distributions to EPO as noncontrolling interest primarily due to a $25.4 million return of contributions in connection with the Enterprise Texas sale of an expansion capital project to Mont Belvieu Caverns.

- § Reimbursements of $85.2 million from EPO as noncontrolling interest related to the Haynesville Extension offset by a $44.1 million decrease in contributions related to expansion projects on the DEP II Midstream Businesses.

- § In June 2009, we completed an offering of 8,000,000 common units that generated net proceeds of approximately $122.9 million after underwriting discounts and other expenses. In July 2009, the underwriters to this offering exercised their option to purchase an additional 943,400 common units, which generated approximately $14.5 million of additional net proceeds. The total net proceeds from this offering, including the overallotment amount, were used to repurchase an equal number of our common units beneficially owned by EPO – 8,000,000 units were repurchased in June 2009 and 943,400 units were repurchased in July 2009. The repurchased common units were subsequently cancelled.

Capital Expenditures

Part of our business strategy involves expansion through business combinations and growth capital projects. The following table summarizes our consolidated capital spending for property, plant and equipment for the periods indicated (dollars in millions):

	For the Nine Months Ended September 30, 2010	2009
DEP I Midstream Businesses:		
Expansion capital spending (1)	$ 394.0	$ 22.3
Sustaining capital expenditures (2)	12.8	10.6
DEP II Midstream Businesses:		
Expansion capital spending (3)	210.6	248.4
Sustaining capital expenditures (2)	32.2	25.2
Total capital spending	$ 649.6	$ 306.5

(1) EPO funded 100% of expansion capital spending for 2009. In 2010, we elected to participate in the Haynesville Extension project with EPO in accordance with our respective ownership interests in Acadian Gas. We have also elected to participate in a smaller Mont Belvieu Caverns project that consists of converting two storage caverns from NGL to refined product service, one of which we expect to place in service in November 2010.

(2) Sustaining capital expenditures are capital expenditures (as defined by U.S. GAAP) resulting from improvements to and major renewals of existing assets. Such expenditures serve to maintain existing operations but do not generate additional revenues. Sustaining capital expenditures reduce the amount of cash distributions paid to Duncan Energy Partners and EPO as owners of these businesses.

(3) EPO funded 100% of expansion capital spending for the periods presented.

The majority of our capital spending during the nine months ended September 30, 2010 and 2009 was attributable to ongoing expansions of the Acadian Gas System and the Texas Intrastate System, including the Haynesville Extension, Eagle Ford and Trinity River Lateral projects.

Based on information currently available, we estimate our consolidated capital spending for property, plant and equipment for the remainder of 2010 will approximate $350 million, which includes estimated expenditures of approximately $340 million for growth capital projects (including approximately $200 million for the Haynesville Extension) and approximately $12 million for sustaining capital expenditures. Our forecast of capital expenditures is based on current announced growth plans.

With respect to growth capital spending, EPO has historically funded the majority of such project costs under agreements executed in connection with the DEP I and DEP II drop down transactions. See

Notes 11 and 13 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report for information regarding EPO's funding of certain growth capital spending.

For information regarding expansion capital funding arrangements with EPO for the Haynesville Extension on Acadian Gas, see "Significant Relationships and Agreements with EPO – Amended Acadian LLC Agreement" under Note 13 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 within this quarterly report. For information regarding the expansion capital funding arrangements of the DEP II Midstream Businesses, see "Significant Relationships and Agreements with EPO - Company and Limited Partnership Agreements - DEP II Midstream Businesses" under Note 13 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 within this quarterly report.

At September 30, 2010, we had approximately $450.6 million in outstanding purchase commitments that relate to our capital spending for property, plant and equipment. These commitments primarily relate to the Haynesville Extension and expansion projects on our Texas Intrastate System.

Pipeline Integrity Costs

Our NGL, petrochemical and natural gas pipelines are subject to pipeline safety programs administered by the U.S. Department of Transportation. This federal agency has issued safety regulations containing requirements for the development of integrity management programs for hazardous liquid pipelines (which include NGL and petrochemical pipelines) and natural gas pipelines. In general, these regulations require companies to assess the condition of their pipelines in certain high consequence areas (as defined by the regulation) and to perform any necessary repairs.

The following table summarizes our pipeline integrity costs for the periods indicated (dollars in millions):

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2010	2009	2010	2009
Expensed	$ 4.3	$ 1.8	$ 10.2	$ 10.3
Capitalized	4.4	4.6	7.3	13.2
Total	$ 8.7	$ 6.4	$ 17.5	$ 23.5

We expect the costs of our pipeline integrity program, irrespective of whether such costs are capitalized or expensed, to approximate $10.6 million for the remainder of 2010.

Critical Accounting Policies and Estimates

A summary of the significant accounting policies we have adopted and followed in the preparation of our consolidated financial statements is included in our 2009 Form 10-K/A. Certain of these accounting policies require the use of estimates. As more fully described therein, the following estimates, in our opinion, are subjective in nature, require the exercise of judgment and involve complex analysis: depreciation methods and estimated useful lives of property, plant and equipment; measuring recoverability of long-lived assets and equity method investments; amortization methods and estimated useful lives of qualifying intangible assets; methods we employ to measure the fair value of goodwill; revenue recognition policies and use of estimates for revenues and expense s; reserves for environmental matters; and natural gas imbalances. These estimates are based on our current knowledge and understanding of the underlying facts and circumstances and may change as a result of actions we take in the future. Changes in these estimates will occur as a result of the passage of time and the occurrence of future events. Subsequent changes in these estimates may have a significant impact on our financial position, results of operations and cash flows.

Other Items

Contractual Obligations

<u>*Scheduled maturities of long-term debt.*</u> Amounts owed under our debt agreements have increased since December 31, 2009 primarily due to borrowings to fund construction costs of the Haynesville Extension. In October 2010, amounts due under our Revolving Credit Facility and the Loan Agreement with EPO were repaid using borrowings under new long-term credit facilities that mature in October 2013. See "Significant Recent Developments – New $1.25 Billion Senior Unsecured Credit Facilities" within this Item 2 for more inform ation related to our new long-term credit facilities.

<u>*Purchase obligations.*</u> There have been no material changes in our consolidated purchase obligations since those reported in our 2009 Form 10-K/A, except for short-term payment obligations relating to capital projects. See "Liquidity and Capital Resources – Capital Expenditures" within this Item 2 for more information related to our capital expenditures.

Insurance Matters

We participate as a named insured in EPCO's insurance program, which provides us with property damage, business interruption and other coverages, the scope and amounts of which we believe are customary and sufficient for the nature and extent of our operations. We recently completed our annual insurance policy renewal process. For additional information regarding insurance matters, see Note 16 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report.

Non-GAAP Reconciliations

A reconciliation of our measurement of total non-GAAP segment gross operating margin to GAAP operating income and further to income before benefit from (provision for) income taxes for the periods indicated (dollars in millions):

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2010	**2009**	**2010**	**2009**
Total non-GAAP segment gross operating margin	$ 74.4	$ 71.6	$ 217.7	$ 190.7
Adjustments to reconcile total non-GAAP segment gross operating margin to GAAP net income:				
Depreciation, amortization and accretion in operating costs and expenses	(49.9)	(47.4)	(149.0)	(137.7)
Non-cash impairment charge	--	--	(1.5)	--
Gains (losses) on asset sales and related transactions in operating costs and expenses	(9.0)	0.1	(8.0)	0.4
General and administrative costs	(6.4)	(3.2)	(16.1)	(8.8)
GAAP operating income	9.1	21.1	43.1	44.6
Other expense, net	(2.9)	(3.4)	(9.2)	(10.5)
Income before benefit from (provision for) income taxes	$ 6.2	$ 17.7	$ 33.9	$ 34.1

Off-Balance Sheet Arrangements

There have been no significant changes with regards to our off-balance sheet arrangements since those reported in our 2009 Form 10-K/A, except Evangeline made a $7.0 million payment, of which $2.7 million was applied to accrued interest and $4.3 million was applied to the subordinated note payable. Evangeline funded this payment using its operating cash flows.

Recent Accounting Developments

In November 2008, the SEC released a proposed roadmap regarding the potential use by U.S. issuers of financial statements prepared in accordance with International Financial Reporting Standards

(“IFRS”). IFRS consist of accounting standards published by the International Accounting Standards Board (“IASB”), which is based in London, England. In February 2010, the SEC expressed its continuing support for a single set of high-quality globally accepted accounting standards and established a general work plan that sets forth areas and factors the SEC will consider before requiring domestic public companies to transition to IFRS. Currently, the Financial Accounting Standards Board (or “FASB,” based in Norwalk, Connecticut) and the IASB are working both individually and jointly on a number of accounting standard convergence projects that, if finalized in 2011, would bring about a significant shift in the accounting and financial reporting landscape. These projects include a broad range of topics such as financial statement presentation, accounting for leases, revenue recognition, finan cial instruments, consolidations and fair value measurements.

The SEC expects to make a determination in 2011 regarding the mandatory adoption of IFRS, with the expectation that any decision to adopt IFRS will allow U.S. issuers a number of years to transition from current U.S. GAAP. We continue to monitor developments regarding the potential implementation of IFRS and the ongoing convergence projects of the FASB and IASB. We will evaluate the impact that any definitive accounting guidance may have on our financial statements once this information is finalized by the appropriate standard setting organizations, including the SEC.

Regulatory Matters

Certain scientific studies have suggested that emissions of certain gases, commonly referred to as “greenhouse gases” and including carbon dioxide (which is a component of, and a product of combustion of, natural gas) and methane (which is a component of natural gas), may be contributing to global climate change and ocean acidification. On June 26, 2009, the U.S. House of Representatives passed the American Clean Energy and Security Act of 2009 (“ACESA”) which, if it were to become law, would establish an economy-wide cap-and-trade program intended to reduce the emissions of greenhouse gases by the United States and would require most significant domestic sources of greenho use gas emissions to obtain greenhouse gas emission “allowances” corresponding to their annual emissions of greenhouse gases. The U.S. Senate has also begun consideration of various legislative proposals for controlling and reducing emissions of greenhouse gases in the United States. In addition, on December 7, 2009, the U.S. Environmental Protection Agency (“EPA”) announced its finding that emissions of greenhouse gases from motor vehicles caused or contributed to climate change and presented an endangerment to human health and the environment. These findings by the EPA were the basis for motor vehicle greenhouse gas emissions standards promulgated on May 7, 2010, and may allow the agency to proceed with the adoption and implementation of additional regulations that would require permits or control emissions of greenhouse gases from industrial sources under existing provisions of the federal Clean Air Act. On May 13, 2010, the EPA issued a final rule setting forth a timetable for its Title V and Prevention of Significant Deterioration regulatory program, applicable in certain circumstances to new and modified industrial source of air emissions, to include consideration of greenhouse gas emissions. The EPA has also received petitions requesting that the agency further expand regulation of greenhouse gas emissions from industrial sources, which, over time, may lead to additional requirements. On April 12, 2010, the EPA proposed new rules that would require the mandatory reporting of greenhouse gas emissions by operators of natural gas compression, processing and storage facilities. These rules supplement disclosures and reporting required by the EPA in its October 30, 2009 mandatory greenhouse gas reporting rule. These and any new laws or regulations that may be adopted to restrict or reduce emissions of greenhouse gases, or that establish new reporting requirements, will require us to incur increased operating costs, and may have an adverse effect on our financial position, results of operations and cash flows.

Related Party Transactions

For information regarding our related party transactions, see Note 13 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report.

Item 3. ***Quantitative and Qualitative Disclosures about Market Risk.***

In the normal course of our business operations, we are exposed to certain risks, including changes in interest rates and commodity prices. In order to manage risks associated with certain anticipated future transactions, we use derivative instruments. Derivatives are financial instruments whose fair value is determined by changes in a specified benchmark such as interest rates, commodity prices or currency values. Typical derivative instruments include physical forward agreements, futures contracts, floating-to-fixed swaps, basis swaps and options contracts. Substantially all of our derivatives are used for non-trading activities. See Note 4 of the Notes to Unaudited Condensed Financial Statements included under Item 1 of this quart erly report for additional information regarding our derivative instruments and hedging activities.

Our exposures to market risk have not changed materially since those reported under Part II, Item 7A, "Quantitative and Qualitative Disclosures About Market Risk," included in our annual report on Form 10-K for the year ended December 31, 2009, as initially filed on March 1, 2010.

Interest Rate Derivative Instruments

We utilized interest rate swaps to manage our exposure to changes in the interest rates charged on borrowings under our Revolving Credit Facility from September 2007 through September 2010. This strategy was a component in controlling our cost of capital associated with such borrowings. Our interest rate swaps expired in September 2010.

Commodity Derivative Instruments

The price of natural gas fluctuates in response to changes in supply and demand, market conditions, and a variety of additional factors that are beyond our control. In order to manage the price risk associated with certain exposures, we enter into commodity derivative instruments such as physical forward agreements, futures contracts, fixed-for-float swaps and basis swaps.

We assess the risk of our commodity derivative instrument portfolio using a sensitivity analysis model. The sensitivity analysis applied to this portfolio measures the potential income or loss (i.e., the change in fair value of the portfolio) based upon a hypothetical 10% movement in the underlying quoted market prices of the commodity derivative instruments outstanding at the date indicated within the following table.

The following table presents the effect of hypothetical price movements (a sensitivity analysis) on the estimated fair value of this portfolio at the dates presented (dollars in millions).

Scenario	Resulting Classification	Portfolio FV at September 30, 2010	Portfolio FV at October 19, 2010
FV assuming no change in underlying commodity prices	*Liability*	$ *	$ --
FV assuming 10% increase in underlying commodity prices	*Liability*	*	--
FV assuming 10% decrease in underlying commodity prices	*Liability*	*	--

* Amount is negligible.

Item 4. ***Controls and Procedures.***

As of the end of the period covered by this quarterly report, our management carried out an evaluation, with the participation of our general partner's CEO (our principal executive officer) and our general partner's chief financial officer (our principal financial officer) (the "CFO"), of the effectiveness of our disclosure controls and procedures pursuant to Rule 13a-15 of the Securities Exchange Act of 1934. Based on that evaluation, as of the end of the period covered by this report, the CEO and CFO concluded:

(i) that our disclosure controls and procedures are designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and that such information is accumulated and communicated to our management, including the CEO and CFO, as appropriate, to allow timely decisions regarding required disclosure; and

(ii) that our disclosure controls and procedures are effective.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934) during the third quarter of 2010, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

The certifications of our general partner's CEO and CFO required under Sections 302 and 906 of the Sarbanes-Oxley Act of 2002 have been included as exhibits to this quarterly report.

PART II. OTHER INFORMATION.

Item 1. *Legal Proceedings*.

For information regarding legal proceedings, see Part I, Item 1, Financial Statements, Note 15, "Commitments and Contingencies – Litigation," of the Notes to Unaudited Condensed Consolidated Financial Statements included in this quarterly report, which is incorporated herein by reference.

Item 1A. *Risk Factors*.

Security holders and potential investors in our securities should carefully consider the risk factors set forth in our 2009 annual report on Form 10-K and below, in addition to other information in such annual report and in this quarterly report on Form 10-Q. We have identified these risk factors as important factors that could cause our actual results to differ materially from those contained in any written or oral forward-looking statements made by us or on our behalf.

Federal and state legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays incurred by customers in the production of natural gas, including from the developing shale plays. A decline in drilling of new wells and related servicing activities caused by these initiatives could adversely affect our financial position, results of operations and cash flows.

Proposals have been introduced in the U.S. Congress to regulate hydraulic fracturing operations and related injection of fracturing fluids and propping agents used in fracturing fluids by the oil and natural gas industry under the federal Safe Drinking Water Act ("SDWA") and to require the disclosure of chemicals used in the hydraulic fracturing process under the SDWA, Emergency Planning and Community Right-to-Know Act, or other authority. Hydraulic fracturing is an important and commonly used process in the completion of unconventional oil and natural gas wells in shale, coal bed and tight sand formations. Sponsors of these bills have asserted that chemicals used in the fracturing process could adversely affect drinking water supplie s and otherwise cause adverse environmental impacts. The Chairman of the House Energy and Commerce Committee has initiated an investigation of the potential impacts of hydraulic fracturing, which has involved seeking information about fracturing activities and chemicals from certain companies in the oil and gas sector. In addition, in March 2010, the U.S. EPA announced its intention to conduct a comprehensive research study on the potential adverse impacts that hydraulic fracturing may have on water quality and public health. The EPA has begun preparation for the study and expects to complete the study in 2012. In addition, various state-level initiatives in regions with substantial shale gas supplies have been proposed or implemented to regulate hydraulic fracturing practices, limit water withdrawals and water use, require disclosure of fracturing fluid constituents, or protect drinking water supplies. Moreover, public debate over hydraulic fracturing and shale gas production has been increasing, and has resulted in delays of well permits in some areas, particularly in the Marcellus Shale play.

Increased regulation and attention given to the hydraulic fracturing process could lead to greater opposition, including litigation, to oil and gas production activities using hydraulic fracturing techniques. Additional legislation or regulation could also lead to operational delays or increased operating costs in the production of natural gas, including from the developing shale plays, incurred by our customers or could make it more difficult to perform hydraulic fracturing. If these legislative and regulatory initiatives cause a material decrease in the drilling of new wells and related well servicing activities, our profitability could be materially impacted.

The adoption and implementation of new statutory and regulatory requirements for derivative transactions could have an adverse impact on our ability to hedge risks associated with our business and increase the working capital requirements to conduct these activities.

The United States Congress has passed, and the President has signed into law, the Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Act"). The Act provides for new statutory and regulatory requirements for financial derivative transactions, including oil and gas hedging transactions. Certain transactions will be required to be cleared on exchanges, and cash collateral will be required for these transactions. The Act provides for a potential exception from these clearing and cash collateral requirements for commercial end-users and it includes a number of defined terms that will be used in determining how this exception applies to particular derivative t ransactions and to the parties to those transactions. The Act requires the Commodity Futures Trading Commission (the "CFTC") to promulgate rules to define these terms in detail, but we do not know the definitions that the CFTC will actually promulgate or how these definitions will apply to us.

The majority of our financial derivative transactions are currently executed and cleared over exchanges that already require the posting of cash collateral or letters of credit based on initial and variation margin requirements. We enter into over the counter natural gas derivative contracts from time to time with respect to a portion of our expected storage activities in order to hedge against commodity price uncertainty and enhance the predictability of cash flows from these activities. Depending on the rules and definitions adopted by the CFTC, we might in the future be required to provide additional cash collateral for our commodities hedging transactions whether cleared over an exchange or new cash collateral for those transactions executed over the counter.□ 60; Posting of additional or new cash collateral could cause liquidity issues for us by reducing our ability to use our cash for capital expenditures or other partnership purposes. A requirement to post additional or new cash collateral could therefore significantly reduce our ability to execute strategic hedges to reduce commodity price uncertainty and thus protect cash flows. We are at risk unless and until the CFTC adopts rules and definitions that confirm that companies such as ourselves are not required to post cash collateral for our over the counter derivative hedging contracts nor increase the amount of cash collateral posted for transactions cleared over an exchange. In addition, even if we ourselves are not required to post cash collateral for our derivative contracts, the banks and other derivatives dealers who are our contractual counterparties will be required to comply with the Act's new requirements. These requirements may affect the liqui dity and pricing of derivative contracts, and the costs of compliance by dealers and counterparties will likely be passed on to customers such as ourselves, thus decreasing the benefits to us of hedging transactions and reducing our profitability.

Item 2. ***Unregistered Sales of Equity Securities and Use of Proceeds.***

None.

Item 3. ***Defaults Upon Senior Securities.***

None.

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Item 4. *(Removed and Reserved).*

Item 5. *Other Information*.

None.

Item 6. *Exhibits.*

Exhibit Number	Exhibit*
3.1	Certificate of Limited Partnership of Duncan Energy Partners L.P. (incorporated by reference to Exhibit 3.1 to Form S-1 Registration Statement (Reg. No. 333-138371) filed November 2, 2006).
3.2	Amended and Restated Agreement of Limited Partnership of Duncan Energy Partners L.P., dated February 5, 2007 (incorporated by reference to Exhibit 3.1 to Form 8-K filed February 5, 2007).
3.3	Amendment No. 1 to the Amended and Restated Agreement of Limited Partnership of Duncan Energy Partners L.P. dated December 27, 2007 (incorporated by reference to Exhibit 3.1 to Form 8-K/A filed January 3, 2008).
3.4	Amendment No. 2 to the Amended and Restated Agreement of Limited Partnership of Duncan Energy Partners L.P. dated November 6, 2008 (incorporated by reference to Exhibit 3.4 to Form 10-Q filed November 10, 2008).
3.5	Third Amendment to the Amended and Restated Agreement of Limited Partnership of Duncan Energy Partners L.P., dated December 8, 2008 (incorporated by reference to Exhibit 3.1 to Form 8-K filed December 8, 2008).
3.6	Fourth Amendment to the Amended and Restated Agreement of Limited Partnership of Duncan Energy Partners L.P. dated June 15, 2009 (incorporated by reference to Exhibit 3.1 to Form 8-K filed June 15, 2009).
3.7	Certificate of Formation of DEP Holdings, LLC (incorporated by reference to Exhibit 3.3 to Form S-1 Registration Statement (Reg. No. 333-138371) filed November 2, 2006).
3.8	Second Amended and Restated Limited Liability Company Agreement of DEP Holdings, LLC, dated May 3, 2007 (incorporated by reference to Exhibit 3.4 to Form 10-Q filed May 4, 2007).
3.9	First Amendment to the Second Amended and Restated Limited Liability Company Agreement of DEP Holdings, LLC dated November 6, 2008 (incorporated by reference to Exhibit 3.8 to Form 10-Q filed November 10, 2008).
3.10	Certificate of Formation of DEP OLPGP, LLC (incorporated by reference to Exhibit 3.5 to Form S-1 Registration Statement (Reg. No. 333-138371) filed November 2, 2006).
3.11	Amended and Restated Limited Liability Company Agreement of DEP OLPGP, LLC, dated January 19, 2007 (incorporated by reference to Exhibit 3.6 to Amendment No. 3 to Form S-1 Registration Statement (Reg. No. 333-138371) filed January 22, 2007).
3.12	Certificate of Limited Partnership of DEP Operating Partnership, L.P. (incorporated by reference to Exhibit 3.7 to Form S-1 Registration Statement (Reg. No. 333-138371) filed November 2, 2006).
3.13	Agreement of Limited Partnership of DEP Operating Partnership, L.P., dated September 29, 2006 (incorporated by reference to Exhibit 3.8 to Amendment No. 1 to Form S-1 Registration Statement (Reg. No. 333-138371) filed December 15, 2006).
10.1***	Amendment to Form of Option Grant Award under the Amended and Restated 2008 Enterprise Products Long-Term Incentive Plan for awards issued before February 23, 2010, (incorporated by reference to Exhibit 10.9 to Form 10-Q filed by Enterprise Products Partners L.P. on August 9, 2010).
10.2***	Amendment to Form of Option Grant Award under the Amended and Restated 2008 Enterprise Products Long-Term Incentive Plan for awards issued before August 5, 2010 (incorporated by reference to Exhibit 10.10 to Form 10-Q filed by Enterprise Products Partners L.P. on August 9, 2010).

10.3***	Form of Option Grant Award under the Amended and Restated 2008 Enterprise Products Long-Term Incentive Plan (incorporated by reference to Exhibit 10.11 to Form 10-Q filed by Enterprise Products Partners L.P. on August 9, 2010).
10.4***	Amendment to Form of Employee Restricted Unit Grant Award under the Amended and Restated 2008 Enterprise Products Long-Term Incentive Plan for awards issued before August 5, 2010 (incorporated by reference to Exhibit 10.12 to Form 10-Q filed by Enterprise Products Partners L.P. on August 9, 2010).
10.5***	Form of Employee Restricted Unit Grant Award under the Amended and Restated 2008 Enterprise Products Long-Term Incentive Plan (incorporated by reference to Exhibit 10.13 to Form 10-Q filed by Enterprise Products Partners L.P. on August 9, 2010).
10.6***	Amendment to Form of Option Grant Award under the Enterprise Products 1998 Long-Term Incentive Plan for awards issued before February 23, 2010 (incorporated by reference to Exhibit 10.1 to Form 10-Q filed by Enterprise Products Partners L.P. on August 9, 2010).
10.7***	Amendment to Form of Option Grant Award under the Enterprise Products 1998 Long-Term Incentive Plan for awards issued before August 5, 2010 (incorporated by reference to Exhibit 10.2 to Form 10-Q filed by Enterprise Products Partners L.P. on August 9, 2010).
10.8***	Form of Option Grant Award under the Enterprise Products 1998 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.3 to Form 10-Q filed by Enterprise Products Partners L.P. on August 9, 2010).
10.9***	Amendment to Form of Employee Restricted Unit Grant Award under the Enterprise Products 1998 Long-Term Incentive Plan for awards issued before August 5, 2010 (incorporated by reference to Exhibit 10.4 to Form 10-Q filed by Enterprise Products Partners L.P. on August 9, 2010).
10.10***	Form of Employee Restricted Unit Grant Award under the Enterprise Products 1998 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.5 to Form 10-Q filed by Enterprise Products Partners L.P. on August 9, 2010).
10.11***	Form of Option Grant Award under the Enterprise Products Company 2005 EPE Long-Term Incentive Plan (incorporated by reference to Exhibit 10.1 to Form 10-Q filed by Enterprise GP Holdings L.P. on August 9, 2010).
10.12***	Form of Employee Restricted Unit Grant Award under the Enterprise Products Company 2005 EPE Long-Term Incentive Plan (incorporated by reference to Exhibit 10.2 to Form 10-Q filed by Enterprise GP Holdings L.P. on August 9, 2010).
10.13***	Form of Phantom Unit Grant Award under the Enterprise Products Company 2005 EPE Long-Term Incentive Plan (incorporated by reference to Exhibit 10.3 to Form 10-Q filed by Enterprise GP Holdings L.P. on August 9, 2010).
10.14***	Form of Option Grant Award under the 2010 Duncan Energy Partners L.P. Long-Term Incentive Plan (incorporated by reference to Exhibit 10.14 to Form 10-Q filed on August 9, 2010).
10.15***	Form of Employee Restricted Unit Grant Award under the 2010 Duncan Energy Partners L.P. Long-Term Incentive Plan (incorporated by reference to Exhibit 10.15 to Form 10-Q filed on August 9, 2010).
10.16	First Amendment to Loan Agreement, dated August 20, 2010, between Enterprise Products Operating LLC, as Lender, and Duncan Energy Partners L.P., as Borrower (incorporated by reference to Exhibit 10.1 to Form 8-K filed on August 23, 2010).
10.17***	Retention Agreement between William Ordemann and Enterprise Products Company dated effective October 1, 2010 (incorporated by reference to Exhibit 10.1 to Form 8-K filed by Enterprise Products Partners L.P. on October 14, 2010).
10.18	Second Amendment to Term Loan Agreement, dated October 25, 2010, among Duncan Energy Partners L.P., as Borrower, Wells Fargo Bank, National Association, successor-by-merger to Wachovia Bank, National Association, as Administrative Agent, and the Lenders party thereto (incorporated by reference to Exhibit 10.1 to Form 8-K filed on October 26, 2010).
10.19	Revolving Credit and Term Loan Agreement, dated October 25, 2010, among Duncan Energy Partners L.P., as Borrower, the Lenders party thereto, Wells Fargo Bank, National Association, as Administrative Agent, Citibank, N.A., DNB NOR Bank ASA and the Royal Bank of Scotland, plc, as Co-Syndication Agents, and Scotia Capital, Barclays Bank plc and Mizuho Corporate Bank, Ltd., as Co-Documentation Agents (incorporated by reference to Exhibit 10.2

	to Form 8-K filed on October 26, 2010).
31.1#	Sarbanes-Oxley Section 302 certification of W. Randall Fowler for Duncan Energy Partners L.P. for the September 30, 2010 quarterly report on Form 10-Q.
31.2#	Sarbanes-Oxley Section 302 certification of Bryan F. Bulawa for Duncan Energy Partners L.P. for the September 30, 2010 quarterly report on Form 10-Q.
32.1#	Section 1350 certification of W. Randall Fowler for the September 30, 2010 quarterly report on Form 10-Q.
32.2#	Section 1350 certification of Bryan F. Bulawa for the September 30, 2010 quarterly report on Form 10-Q.

*****	With respect to exhibits incorporated by reference to Exchange Act filings, the Commission file numbers for Enterprise Products Partners L.P. and Enterprise GP Holdings L.P. are 1-14323 and 1-32610, respectively.
*******	Identifies management contract and compensatory plan arrangements.
#	Filed with this report.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized on November 9, 2010.

DUNCAN ENERGY PARTNERS L.P.
(A Delaware Limited Partnership)

By: DEP Holdings, LLC, as General Partner

By: /s/ Michael J. Knesek
Name: Michael J. Knesek
Title: Senior Vice President, Controller
and Principal Accounting Officer
of the General Partner

EXHIBIT 31.1

CERTIFICATIONS

I, W. Randall Fowler, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Duncan Energy Partners L.P.;

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

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

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

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

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

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 9, 2010

/s/ W. Randall Fowler

Name: W. Randall Fowler
Title: Chief Executive Officer of DEP Holdings, LLC, the General Partner of Duncan Energy Partners L.P.

EXHIBIT 31.2

CERTIFICATIONS

I, Bryan F. Bulawa, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Duncan Energy Partners L.P.;

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

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

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

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

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

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 9, 2010

/s/ Bryan F. Bulawa
Name: Bryan F. Bulawa
Title: Chief Financial Officer of DEP Holdings, LLC, the General Partner of Duncan Energy Partners L.P.

EXHIBIT 32.1

SARBANES-OXLEY SECTION 906 CERTIFICATION

CERTIFICATION OF W. RANDALL FOWLER, CHIEF EXECUTIVE OFFICER OF DEP HOLDINGS, LLC, THE GENERAL PARTNER OF DUNCAN ENERGY PARTNERS L.P.

In connection with this quarterly report of Duncan Energy Partners L.P. (the "Registrant") on Form 10-Q for the quarterly period ended September 30, 2010 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, W. Randall Fowler, Chief Executive Officer of DEP Holdings, LLC, the General Partner of the Registrant, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Registrant.

/s/ W. Randall Fowler

Name: W. Randall Fowler
Title: Chief Executive Officer of DEP Holdings, LLC,
the General Partner of Duncan Energy Partners L.P.

Date: November 9, 2010

EXHIBIT 32.2

SARBANES-OXLEY SECTION 906 CERTIFICATION

CERTIFICATION OF BRYAN F. BULAWA, CHIEF FINANCIAL OFFICER OF DEP HOLDINGS, LLC, THE GENERAL PARTNER OF DUNCAN ENERGY PARTNERS L.P.

In connection with this quarterly report of Duncan Energy Partners L.P. (the “Registrant”) on Form 10-Q for the quarterly period ended September 30, 2010 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Bryan F. Bulawa, Chief Financial Officer of DEP Holdings, LLC, the General Partner of the Registrant, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Registrant.

/s/ Bryan F. Bulawa

Name: Bryan F. Bulawa
Title: Chief Financial Officer of DEP Holdings, LLC
the General Partner of Duncan Energy Partners L.P.

Date: November 9, 2010