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

FORM 10-Q

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

For the quarterly period ended June 30, 2011

OR

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

For the transition period from ___ to ___.

Commission file number: 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 ☑ 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 57,792,270 common units of Duncan Energy Partners L.P. outstanding at July 31, 2011. Our common units trade on the New York Stock Exchange under the ticker symbol “DEP.”

DUNCAN ENERGY PARTNERS L.P.
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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)

	June 30, 2011	December 31, 2010
ASSETS		
Current assets:		
Cash and cash equivalents	$ 18.6	$ 32.4
Accounts receivable – trade, net of allowance for doubtful accounts of $0.5 and $0.4 at June 30, 2011 and December 31, 2010, respectively.	77.5	66.0
Accounts receivable – related parties	55.1	21.1
Gas imbalance receivables	2.6	11.5
Inventories	15.9	5.8
Prepaid and other current assets	24.6	19.3
Total current assets	194.3	156.1
Property, plant and equipment, net	6,193.9	5,362.2
Investment in Evangeline	5.6	6.4
Intangible assets, net of accumulated amortization of $54.7 and $50.8 at June 30, 2011 and December 31, 2010, respectively.	34.1	38.0
Goodwill	4.9	4.9
Other assets (see Note 16)	40.4	4.3
Total assets	$ 6,473.2	$ 5,571.9
LIABILITIES AND EQUITY		
Current liabilities:		
Current maturities of debt	$ 282.3	$ 282.3
Accounts payable – trade	197.1	99.3
Accounts payable – related parties	74.3	26.8
Accrued product payables	50.9	60.5
Accrued costs and expenses	18.4	11.5
Other current liabilities	56.1	47.2
Total current liabilities	679.1	527.6
Long-term debt (see Note 9)	867.5	506.0
Deferred tax liabilities	5.9	5.3
Other long-term liabilities	14.9	13.4
Commitments and contingencies		
Equity:		
Partners' equity: (see Note 10)		
Limited partners:		
Common units (57,792,270 and 57,749,158 common units outstanding at June 30, 2011 and December 31, 2010, respectively)	754.2	760.3
General partner	(0.1)	0.1
Total partners' equity	754.1	760.4
Noncontrolling interest in subsidiaries: (see Note 11)		
DEP I Midstream Businesses – Parent	875.0	686.7
DEP II Midstream Businesses – Parent	3,276.7	3,072.5
Total noncontrolling interest	4,151.7	3,759.2
Total equity	4,905.8	4,519.6
Total liabilities and equity	$ 6,473.2	$ 5,571.9

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, except per unit amounts)

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2011	**2010**	**2011**	**2010**
Revenues:				
Third parties	$ 140.0	$ 124.2	$ 283.1	$ 282.4
Related parties	162.8	141.0	302.9	273.4
Total revenues (see Note 12)	302.8	265.2	586.0	555.8
Costs and Expenses:				
Operating costs and expenses:				
Third parties	213.2	204.1	403.5	429.8
Related parties	54.6	41.0	121.3	82.5
Total operating costs and expenses	267.8	245.1	524.8	512.3
General and administrative costs:				
Third parties	1.7	1.5	2.3	2.2
Related parties	4.8	3.3	8.8	7.5
Total general and administrative costs	6.5	4.8	11.1	9.7
Total costs and expenses (see Note 12)	274.3	249.9	535.9	522.0
Equity in income of Evangeline	0.5	--	0.8	0.2
Operating income	29.0	15.3	50.9	34.0
Interest expense	2.9	3.2	6.0	6.3
Income before provision for income taxes	26.1	12.1	44.9	27.7
Provision for income taxes	(0.5)	(0.3)	(1.0)	(0.2)
Net income	25.6	11.8	43.9	27.5
Net loss (income) attributable to noncontrolling interest: (see Note 11)				
DEP I Midstream Businesses - Parent	(5.6)	(7.8)	(3.1)	(12.5)
DEP II Midstream Businesses - Parent	2.5	19.3	1.0	29.5
Total net loss (income) attributable to noncontrolling interest	(3.1)	11.5	(2.1)	17.0
Net income attributable to partners (see Note 1)	$ 22.5	$ 23.3	$ 41.8	$ 44.5
Allocation of net income attributable to partners: (see Note 1)				
Limited partners	$ 22.3	$ 23.2	$ 41.5	$ 44.2
General partner	$ 0.2	$ 0.1	$ 0.3	$ 0.3
Earnings per unit (see Note 14)	$ 0.39	$ 0.40	$ 0.72	$ 0.77

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 June 30,		For the Six Months Ended June 30,	
	2011	**2010**	**2011**	**2010**
Net income	$ 25.6	$ 11.8	$ 43.9	$ 27.5
Other comprehensive income (loss):				
Cash flow hedges:				
Commodity derivative instrument losses during period	--	(0.1)	--	(0.1)
Interest rate derivative instrument gains (losses) during period	--	0.1	--	(0.1)
Reclassification adjustment for losses included in net income related to interest rate derivative instruments	--	1.9	--	3.8
Total other comprehensive income	--	1.9	--	3.6
Comprehensive income	25.6	13.7	43.9	31.1
Comprehensive loss (income) attributable to noncontrolling interest:				
DEP I Midstream Businesses – Parent	(5.6)	(7.8)	(3.1)	(12.5)
DEP II Midstream Businesses – Parent	2.5	19.3	1.0	29.5
Total comprehensive loss (income) attributable to noncontrolling interest	(3.1)	11.5	(2.1)	17.0
Comprehensive income attributable to partners	$ 22.5	$ 25.2	$ 41.8	$ 48.1

See Notes to Unaudited Condensed Consolidated Financial Statements.

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

	For the Six Months Ended June 30, 2011	For the Six Months Ended June 30, 2010
Operating activities:		
Net income	$ 43.9	$ 27.5
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion	106.4	100.5
Non-cash asset impairment charges	--	1.5
Equity in income of Evangeline	(0.8)	(0.2)
Distribution received from Evangeline	1.5	--
Gains from asset sales and related transactions	(0.5)	(1.0)
Deferred income tax expense	0.5	(0.3)
Net effect of changes in operating accounts (see Note 17)	(18.7)	(21.5)
Cash flows provided by operating activities	132.3	106.5
Investing activities:		
Capital expenditures	(847.9)	(343.3)
Contributions in aid of construction costs	4.9	4.6
Proceeds from sale of assets and related transactions	0.1	2.3
Other, including loans to EPO (see Note 13)	--	45.5
Cash used in investing activities	(842.9)	(290.9)
Financing activities:		
Borrowings under bank agreements	419.0	103.1
Repayments of debt under bank agreements	(57.5)	(23.1)
Cash distributions to our unitholders and general partner	(53.1)	(51.9)
Cash distributions to EPO as noncontrolling interest	(62.5)	(40.3)
Cash contributions from EPO as noncontrolling interest	449.4	213.2
Net cash proceeds from the issuance of common units	1.5	0.8
Cash provided by financing activities	696.8	201.8
Net changes in cash and cash equivalents	(13.8)	17.4
Cash and cash equivalents, January 1	32.4	3.9
Cash and cash equivalents, June 30	$ 18.6	$ 21.3

See Notes to Unaudited Condensed Consolidated Financial Statements.

DUNCAN ENERGY PARTNERS L.P.
UNAUDITED CONDENSED STATEMENTS OF CONSOLIDATED EQUITY
(See Note 10 for Unit History)
(Dollars in millions)

	Duncan Energy Partners			
	Limited Partners	General Partner	Noncontrolling Interest in Subsidiaries	Total
Balance, December 31, 2010	$ 760.3	$ 0.1	$ 3,759.2	$ 4,519.6
Net income	41.5	0.3	2.1	43.9
Amortization of equity awards	3.5	--	--	3.5
Net cash proceeds from the issuance of common units	1.5	--	--	1.5
Cash distributions to unitholders and general partner	(52.7)	(0.4)	--	(53.1)
Cash contributions from EPO as noncontrolling interest	--	--	449.4	449.4
Cash distributions to EPO as noncontrolling interest	--	--	(62.5)	(62.5)
Other	0.1	(0.1)	3.5	3.5
Balance, June 30, 2011	$ 754.2	$ (0.1)	$ 4,151.7	$ 4,905.8

	Duncan Energy Partners				
	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 (loss)	44.2	0.3	--	(17.0)	27.5
Amortization of equity awards	2.0	--	--	--	2.0
Net cash proceeds from the issuance of common units	0.8	--	--	--	0.8
Cash distributions to unitholders and general partner	(51.5)	(0.4)	--	--	(51.9)
Cash contributions from EPO as noncontrolling interest	--	--	--	213.2	213.2
Cash distributions to EPO as noncontrolling interest	--	--	--	(40.3)	(40.3)
Change in value of cash flow hedges	--	--	3.6	--	3.6
Other	--	--	--	8.1	8.1
Balance, June 30, 2010	$ 762.1	$ 0.1	$ (1.8)	$ 3,539.5	$ 4,299.9

See Notes to Unaudited Condensed Consolidated Financial Statements.

DUNCAN ENERGY PARTNERS L.P.
NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Except per unit amounts, or as noted within the context of each footnote disclosure, dollar amounts presented in the tabular data within these footnote disclosures 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" mean the business and operations of Enterprise Products Partners L.P. and its consolidated subsidiaries. Enterprise 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." Enterprise is managed by its general partner, Enterprise Products Holdings LLC ("Enterprise GP"), which is a wholly owned subsidiary of Dan Duncan LLC, a Delaware limited liability company. References to "EPO" mean Enterprise Products Operating LLC, which is a wholly owned subsidiary of Enterprise and its consolidated subsidiaries, through which Enterprise conducts substantially all of its business. EPO beneficially owns 100% of DEP GP and currently owns 58.5% of our common units. Enterprise consolidates our financial statements with its own.

On April 28, 2011, we and our general partner entered into a definitive merger agreement with Enterprise, Enterprise GP and certain of their subsidiaries. See Note 13 for information regarding the proposed merger with Enterprise.

The membership interests of Dan Duncan LLC are owned of record by a voting trust, the current trustees ("DD LLC Trustees") of which are: (i) Randa Duncan Williams, who is also a director of Enterprise GP; (ii) Dr. Ralph S. Cunningham, who is also a director and the Chairman of Enterprise GP and one of three managers of Dan Duncan LLC; and (iii) Richard H. Bachmann, who is also a director of Enterprise GP and one of three managers of Dan Duncan LLC.

References to "EPCO" mean Enterprise Products Company and its privately held affiliates. A majority of the outstanding voting capital stock of EPCO is owned of record by a voting trust, the current trustees ("EPCO Trustees") of which 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 and Chief Executive Officer ("CEO") of EPCO. Ms. Williams, Dr. Cunningham and Mr. Bachmann are also currently directors of EPCO.

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. (NYSE: ETE) and its consolidated subsidiaries, which include Energy Transfer Partners, L.P. ("ETP") and Regency Energy Partners LP ("RGNC"). The general partner of Energy Transfer Equity is LE GP, LLC ("LE GP"). Enterprise owns noncontrolling interests in Energy Transfer Equity, which it accounts for using the equity method of accounting.

Note 1. Partnership Operations, Organization 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 in September 2006 and did not own any assets prior to February 5, 2007, which was the date we completed our initial public offering and acquired controlling interests in the DEP I Midstream Businesses from EPO. 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, petrochemical and refined 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: 11,201 miles of natural gas, NGL and petrochemical pipelines; two NGL fractionation facilities; approximately 17.3 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 approximately 100 MMBbls of NGL and related product 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.

We have three reportable business segments: (i) Natural Gas Pipelines & Services; (ii) NGL 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.

At June 30, 2011, we are owned 99.3% by our limited partners and 0.7% by our general partner, DEP GP. EPO beneficially owned approximately 58.5% of our limited partner interests and 100% of DEP GP. On April 28, 2011, we and our general partner entered into a definitive merger agreement with Enterprise, Enterprise GP and certain of their subsidiaries. See Note 13 for information regarding the proposed merger with Enterprise.

We, DEP GP, EPO, Enterprise, Enterprise GP, 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, which 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.

See Note 16 for information regarding a February 2011 NGL release and fire at the West Storage location of our Mont Belvieu, Texas underground storage facility.

§ 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 approximately 1.1 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 central and southern 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 1.8 Bcf/d of natural gas from the Haynesville area through a 270-mile pipeline that will connect with our existing Acadian Gas System. The Haynesville Extension is expected to be completed in September 2011.

The total budgeted cost of the Haynesville Extension is approximately $1.50 billion (including capitalized interest). In June 2010, we agreed to fund 66% of the Haynesville Extension project costs and EPO agreed to fund the remaining 34% of such expenditures; therefore, we estimate that our share of such costs will approximate $990 million. In order to fund our capital spending requirements under the Haynesville Extension project, we entered into long-term senior unsecured credit facilities having an aggregate borrowing capacity of $1.25 billion in October 2010. For information regarding our $1.25 billion credit facilities, see Note 9.

§ Lou-Tex Propylene owns a 267-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 1,185-mile NGL pipeline system located in South Texas; and (iii) 1,096 miles of natural gas gathering pipelines located in South and West Texas. Enterprise GC's natural gas gathering pipelines include: (i) the 262-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 174-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 6,653-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 pipeline system and the Wilson storage facility, 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. 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 supply basin located in South Texas. We are in the process of expanding this system's natural gas gathering and transportation capabilities as well as increasing our natural gas storage capacity 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 "Relationship 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 (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 allocated 98% to EPO and 2% to us.

The initial annualized return rate from December 8, 2008 through December 31, 2009 was 11.85%, which was 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 2010 was 12.087% and for 2011 is 12.329%.

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 DEP II Midstream Business. 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.

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

Note 2. General Accounting Matters

Our results of operations for the three and six months ended June 30, 2011 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, 2010 ("2010 Form 10-K"), as filed on March 1, 2011.

Allowance for Doubtful Accounts

Our allowance for doubtful accounts is determined based on specific identification and estimates of future uncollectible accounts. Our procedure for determining the allowance for doubtful accounts is based on: (i) historical experience with customers, (ii) the perceived financial stability of customers based on our research and (iii) the levels of credit we grant to customers. In addition, we may increase the allowance account in response to the specific identification of customers involved in bankruptcy proceedings and similar financial difficulties. On a routine basis, we review estimates associated with the allowance for doubtful accounts to ensure that we have recorded sufficient reserves to cover potential losses. Our allowance also includes estimates for uncollectible natural gas imbalances based on specific identification of accounts.

Contingencies

Certain conditions may exist as of the date our financial statements are issued, which may result in a loss to us but which will only be resolved when one or more future events occur or fail to occur. Management has regular quarterly litigation reviews, including updates from legal counsel, to assess the need for accounting recognition or disclosure of these contingencies, and such assessment inherently involves an exercise in judgment. In assessing loss contingencies related to legal proceedings that are pending against us or unasserted claims that may result in proceedings, our management and legal counsel evaluate the perceived merits of any legal proceedings or unasserted claims as well as the perceived merits of the amount of relief sought or expected to be sought therein.

We accrue an undiscounted liability for those contingencies where the incurrence of a loss is probable and the amount can be reasonably estimated. If a range of amounts can be reasonably estimated and no amount within the range is a better estimate than any other amount, then the minimum of the range is accrued. We do not record a contingent liability when the likelihood of loss is probable but the amount cannot be reasonably estimated or when it is believed to be only reasonably possible or remote. For contingencies where an unfavorable outcome is reasonably possible and the impact would be material, we disclose the nature of the contingency and, where feasible, an estimate of the possible loss or range of loss. Loss contingencies considered remote are generally not disclosed unless they involve guarantees, in which case the guarantees would be disclosed. See Note 15 for additional information regarding our contingencies.

Derivative Instruments

We use derivative instruments such as physical forward agreements, futures contracts, floating-to-fixed swaps, basis swaps and options contracts to manage price risks associated with inventories, firm commitments, interest rates and certain anticipated transactions. To qualify for hedge accounting, the item to be hedged must expose us to risk and the related derivative instrument must reduce that exposure and meet specific documentation requirements. We formally designate a derivative instrument as a hedge and document and assess the effectiveness of the hedge at inception and thereafter on a quarterly basis.

We apply the normal purchases/normal sales exception for certain of our derivative instruments, which precludes the recognition of changes in mark-to-market values for these items on our balance sheet or income statement. Revenues and costs for these transactions are recognized when volumes are physically delivered or received.

See Note 4 for additional information regarding our derivative instruments and related hedging activities.

Earnings Per Unit

Earnings per unit is based on the amount of net income allocated to limited partners and the weighted-average number of units outstanding during the period. See Note 14 for information regarding our presentation of earnings per unit amounts.

Estimates

Preparing our financial statements in conformity with GAAP requires management to make estimates and assumptions that affect amounts presented in the financial statements (i.e., assets, liabilities, revenue and expenses) and disclosures about 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

The carrying amounts of cash and cash equivalents, accounts receivable and accounts payable approximate their fair value. 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.

Recent Accounting Developments

Fair Value Measurements. In May 2011, the Financial Accounting Standards Board (or "FASB") issued an accounting standard update that amended previous fair value measurement and disclosure guidance. These amendments generally involve clarifications on how to measure and disclose fair value amounts recognized in the financial statements. They also expand the disclosure requirements, particularly for Level 3 fair value measurements, to include a description of the valuation processes used and an analysis of the sensitivity of the fair value measurements to changes in unobservable inputs and the interrelationships between those unobservable inputs, if any. We will adopt this guidance on January 1, 2012 and apply its requirements prospectively at that time. We do not believe the adoption of this guidance will have a material impact on our consolidated financial statements.

Presentation of Other Comprehensive Income. In June 2011, the FASB issued an accounting standard update that revised the financial statement presentation of other comprehensive income ("OCI"). The amended guidance requires entities to present components of comprehensive income in either (i) a single continuous statement of comprehensive income or (ii) two separate but consecutive statements (i.e., an income statement and a comprehensive income statement, which is our current format). Although the amended guidance does not change the items that must be reported in OCI, reclassification adjustments for each component of OCI will have to be displayed in both net income and OCI. We will adopt this guidance on January 1, 2012 and apply its presentation requirements retrospectively at that time. We do not believe the adoption of this guidance will have a material impact on our consolidated financial statements.

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 presented:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2011	2010	2011	2010
Restricted common unit awards	$ 1.8	$ 1.0	$ 3.3	$ 1.6
Unit option awards	0.1	*	0.2	0.1
Other	--	0.2	--	0.3
Total compensation expense	$ 1.9	$ 1.2	$ 3.5	$ 2.0

* Amount is negligible.

The fair value of equity-classified awards (e.g., restricted common unit and unit option awards) is amortized to earnings over the requisite service or vesting period. Compensation expense for potential liability-classified awards (e.g., unit appreciation rights ("UARs") and phantom units) would be recognized over the requisite service or vesting period of an award based on the fair value of the award as remeasured at each reporting period. Liability-classified awards are settled in cash upon vesting.

At June 30, 2011, EPCO's significant long-term incentive plans applicable to us were the 2010 Duncan Energy Partners L.P. Long-Term Incentive Plan (the "2010 Plan"), the Enterprise Products 1998 Long-Term Incentive Plan ("1998 Plan") and the Amended and Restated 2008 Enterprise Products Long-Term Incentive Plan ("2008 Plan").

The 2010 Plan provides for awards to employees, directors or consultants providing services to us. Awards under the 2010 Plan may be granted in the form of options to purchase our common units, restricted common units, UARs, phantom units and distribution equivalent rights ("DERs"). Up to 500,000 of our common units may be issued as awards under the 2010 Plan. After giving effect to awards granted under the plan through June 30, 2011, a total of 489,986 additional common units could be issued. The merger agreement governing our proposed merger with Enterprise contains restrictions on the issuance of additional awards under the 2010 Plan. See Note 13 for information regarding the proposed merger with Enterprise.

The 1998 Plan provides for awards of Enterprise's common units and other rights to non-employee directors and to employees of EPCO and its affiliates providing services to us. Awards under the 1998 Plan may be granted in the form of unit options, restricted common units, phantom units and DERs. Up to 7,000,000 of Enterprise's common units may be issued as awards under the 1998 Plan. After giving effect to awards granted under the plan through June 30, 2011, a total of 1,475,190 additional common units of Enterprise could be issued. We are allocated expense associated with certain unit options and restricted common units issued under the 1998 Plan.

The 2008 Plan provides for awards of Enterprise's common units and other rights to non-employee directors and to consultants and employees of EPCO and its affiliates providing services to us. Awards under the 2008 Plan may be granted in the form of unit options, restricted common units, UARs, phantom units and DERs. Up to 10,000,000 of Enterprise's common units may be issued as awards under the 2008 Plan. After giving effect to awards granted under the plan through June 30, 2011, a total of 4,706,877 additional common units of Enterprise could be issued. We are allocated expense associated with certain unit options and restricted common units issued under the 2008 Plan.

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 June 30, 2011, we have not been allocated any costs of liability-classified awards and therefore have not included any discussion of such awards 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 (to EPCO and 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 Common Unit Awards

Restricted common 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 common unit awards may be denominated in our common units or those of Enterprise depending on the issuer of the award. Restricted common unit awards issued prior to 2010 generally cliff vest four years from the date of grant. Beginning with awards issued in 2010, restricted common 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 common unit" represents a time-vested unit. Such awards are non-vested until the required service period expires.

The fair value of a restricted common 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 common unit awards for the period presented:

	Number of Units	Weighted-Average Grant Date Fair Value per Unit (1)
Enterprise restricted common unit awards		
Restricted common units at December 31, 2010	3,561,614	$ 29.78
Granted (2)	1,359,230	$ 43.68
Vested	(828,545)	$ 31.57
Forfeited	(75,857)	$ 32.67
Restricted common units at June 30, 2011	4,016,442	$ 34.06
Duncan Energy Partners restricted common unit awards		
Restricted common units at December 31, 2010	--	$ --
Granted (3)	3,666	$ 32.56
Vested (3)	(3,666)	$ 32.56
Restricted common units at June 30, 2011	--	$ --

(1) Determined by dividing the aggregate grant date fair value of awards before an allowance for forfeitures by the number of awards issued.
(2) The aggregate grant date fair value of restricted common unit awards issued in 2011 was $59.4 million based on a grant date market price of Enterprise's common units ranging from $40.54 to $43.70 per unit. An estimated annual forfeiture rate of 4.6% was applied to these awards.
(3) The aggregate grant date fair value of restricted common unit awards issued in 2011 was $0.1 million based on a grant date market price of our common units of $32.56 per unit. These awards vested upon issuance.

For the EPCO group of companies, the unrecognized compensation cost associated with restricted common unit awards was an aggregate $73.5 million at June 30, 2011, of which our allocated share of the cost is currently estimated to be $10.0 million. We expect to recognize our share of the unrecognized compensation cost for these awards over a weighted-average period of 2.0 years.

Unit Option Awards

EPCO's long-term incentive plans provide for the issuance of non-qualified incentive options. These unit option awards may be denominated in our common units or those of Enterprise depending on the issuer of the award. When issued, the exercise price of each unit option award may be no less than the market price of the underlying security on the date of grant. In general, these unit option awards have a vesting period of four years from the date of grant and expire five years after the date of grant. There were no options granted under our 2010 Plan during the three and six months ended June 30, 2011.

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 options, risk-free interest rates, expected distribution yield of the underlying security, and expected unit price volatility. In general, our assumptions regarding the expected life of the options represent the period of time that the options are expected to be outstanding based on an analysis of our historical option activity. Our selection of the risk-free interest rates is based on published yields for U.S. government securities with comparable terms. The unit price volatility and expected distribution yield assumptions are based on several factors, including an analysis of the underlying security's historical market price and its distribution yield over a period of time equal to the expected life of the option, respectively. Compensation expense recorded in connection with unit options is based on the grant date fair value of such awards, net of an allowance for estimated forfeitures, over the requisite service or vesting period.

The following table presents unit option activity for the period presented. As of June 30, 2011, only Enterprise has issued 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, 2010	3,753,420	$ 28.08	3.6	$ --
Unit options at June 30, 2011	3,753,420	$ 28.08	3.1	$ 7.3
Unit options exercisable at June 30, 2011 (2)	--		--	$ --

(1) Aggregate intrinsic value reflects fully vested unit options at the date indicated. There were no vested unit options outstanding at December 31, 2010.
(2) Enterprise was committed to issue 3,753,420 common units at June 30, 2011 if all outstanding options awarded were exercised. Option awards outstanding at June 30, 2011 include 612,280 awards that vested during the first six months of 2011. Of the remaining outstanding option awards at June 30, 2011, 100,000; 736,000; 1,520,140 and 785,000 will vest in 2011, 2012, 2013, and 2014, respectively. These unit option awards become exercisable in the calendar year following the year in which they vest.

In order to fund its unit option-related obligations, EPCO may purchase common units at fair value either in the open market or directly from Enterprise.

For the EPCO group of companies, the unrecognized compensation cost associated with unit option awards was an aggregate $5.0 million at June 30, 2011, of which our allocated share of the cost is currently estimated to be $0.8 million. We expect to recognize our share of the unrecognized compensation cost for these awards over a weighted-average period of 1.9 years.

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 financial 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. Derivative instruments typically 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 our 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 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 things, 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 have no interest rate derivative instruments outstanding at June 30, 2011. We utilized floating-to-fixed interest rate swaps with a notional value of $175.0 million to manage our exposure to changes in the interest rates charged on borrowings under a then existing $300.0 million unsecured revolving credit facility from September 2007 through September 2010. Our interest rate swaps expired in September 2010. This strategy was a component in controlling our cost of capital associated with such borrowings for the three and six months ended June 30, 2010.

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 $1.9 million and $3.8 million for the three and six months ended June 30, 2010, respectively.

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 such price risks, we enter into commodity derivative instruments such as forwards, basis swaps and futures contracts. The following table summarizes our commodity derivative instruments outstanding at June 30, 2011:

	Volume (1)		Accounting
Derivative Purpose	**Current**	**Long-Term**	**Treatment**
Derivatives not designated as hedging instruments:			
Acadian Gas:			
Natural gas risk management activities (2)	0.2 Bcf	n/a	Mark-to-market

(1) This 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. At June 30, 2011, we did not have any derivative instruments with contingent features in a net liability position. 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			
	June 30, 2011		December 31, 2010		June 30, 2011		December 31, 2010	
	Balance Sheet Location	**Fair Value**	**Balance Sheet Location**	**Fair Value**	**Balance Sheet Location**	**Fair Value**	**Balance Sheet Location**	**Fair Value**
Derivatives not designated as hedging instruments:								
Commodity derivatives	Other current assets	$ *	Other current assets	$ 0.2	Other current liabilities	$ *	Other current liabilities	$ 0.2

* Amount is negligible.

The following tables present 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 presented:

Derivatives in Cash Flow Hedging Relationships	Change in Value Recognized in Other Comprehensive Income on Derivative (Effective Portion)			
	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2011	2010	2011	2010
Interest rate derivatives	$ --	$ 0.1	$ --	$ (0.1)
Commodity derivatives	--	(0.1)	--	(0.1)
Total	$ --	$ *	$ --	$ (0.2)

* Amount is negligible.

Derivatives in Cash Flow Hedging Relationships	Location	Loss Reclassified from Accumulated Other Comprehensive Loss to Income (Effective Portion)			
		For the Three Months Ended June 30,		For the Six Months Ended June 30,	
		2011	2010	2011	2010
Interest rate derivatives	Interest expense	$ --	$ (1.9)	$ --	$ (3.8)

Derivatives in Cash Flow Hedging Relationships	Location	Gain Recognized in Income on Derivative (Ineffective Portion)			
		For the Three Months Ended June 30,		For the Six Months Ended June 30,	
		2011	2010	2011	2010
Interest rate derivatives	Interest expense	$ --	$ *	$ --	$ *

* Amount is negligible.

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 presented:

Derivatives Not Designated as Hedging Instruments	Location	Loss Recognized in Income on Derivative			
		For the Three Months Ended June 30,		For the Six Months Ended June 30,	
		2011	2010	2011	2010
Commodity derivatives	Revenue	$ *	$ (0.3)	$ (0.2)	$ (0.3)

* Amount is negligible.

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. Our Level 1 and 2 assets were nominal amounts at June 30, 2011 and we did not have any Level 3 assets. There were no transfers between Levels 1, 2 or 3 during the six months ended June 30, 2011.

Nonfinancial Assets and Liabilities

Using appropriate valuation techniques, we adjusted the carrying value of certain assets recorded as property, plant and equipment to their estimated fair values during the six months ended June 30, 2010. This resulted in non-cash asset impairment charges of $1.5 million. These impairment charges resulted primarily from the anticipated abandonment of certain pipeline laterals on our TPC Offshore gathering system and the cancellation of a compressor station project on our Texas Intrastate System. Our fair value estimates were based primarily on an evaluation of the future cash flows associated with each asset (Level 3). The non-cash asset impairment charges we recorded during the three and six months ended June 30, 2010 are a component of operating costs and expenses. We did not have any non-cash impairment charges during the six months ended June 30, 2011.

Note 5. Inventories

Inventories consist of natural gas and NGLs that are held for sale and valued at the lower of average cost or market and natural gas held for operational system balancing. Natural gas volumes used for operational system balancing fluctuate as a result of imbalances with shippers and are valued based on a twelve-month rolling average of posted industry prices. Our inventory amounts by product type were as follows at the dates indicated:

	June 30, 2011	December 31, 2010
Natural gas	$ 14.3	$ 5.7
NGLs	1.6	0.1
	$ 15.9	$ 5.8

Our cost of sales amounts were $153.5 million and $136.9 million for the three months ended June 30, 2011 and 2010, respectively. Cost of sales were $294.2 million and $299.7 million for the six months ended June 30, 2011 and 2010, respectively. Period-to-period fluctuations in our costs of sales amounts are primarily due to changes in natural gas prices and sales volumes. Cost of sales is a component of “Operating costs and expenses” as presented on our Unaudited Condensed Statements of Consolidated Operations.

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	June 30, 2011	December 31, 2010
Plant and pipeline facilities (1)	3-45 (4)	$ 5,256.5	$ 5,118.6
Underground storage wells and related assets (2)	5-35 (5)	518.2	474.2
Transportation equipment (3)	3-10	13.5	13.0
Land		46.8	46.0
Construction in progress		1,552.8	807.4
Total		7,387.8	6,459.2
Less accumulated depreciation		1,193.9	1,097.0
Property, plant and equipment, net		$ 6,193.9	$ 5,362.2

(1) Includes natural gas, NGL and petrochemical pipelines, NGL fractionation facilities, office furniture and equipment, buildings and related assets.
(2) Underground storage facilities include 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 assets within this category are: 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 underground storage facilities is 20-35 years (with some components at 5 years).

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2011	2010	2011	2010
Depreciation expense (1)	$ 49.3	$ 48.3	$ 97.2	$ 93.9
Capitalized interest (2, 3)	3.8	0.2	6.2	0.3

(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.
(3) The increase in capitalized interest for 2011 is due to our election to fund the Haynesville Extension in line with our respective ownership interest.

Haynesville Extension

On a consolidated basis, our construction in progress amounts at June 30, 2011 includes $1.17 billion 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 $350 million for the remainder of 2011 and $1.50 billion for the entire project through the date of completion, which is expected in September 2011.

Our 66% share of the total expected cost of the Haynesville Extension is estimated at $990 million. We expect that our 66% share of the capital spending for this project for the remainder of 2011 will approximate $230 million. For information regarding the funding of the Haynesville Extension, see “Relationship 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 contractual 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 regulatory requirements associated with the renovation or demolition of certain assets containing hazardous substances such as asbestos. The following table presents information regarding our AROs since December 31, 2010:

ARO liability balance, December 31, 2010	$ 15.6
Liabilities settled during the period	(0.9)
Accretion expense	0.6
Revisions in estimated cash flows	1.1
ARO liability balance, June 30, 2011	$ 16.4

Property, plant and equipment at June 30, 2011 and December 31, 2010 includes $10.7 million and $9.4 million, respectively, of asset retirement costs capitalized as an increase in the associated long-lived assets. The following table presents our accretion expense forecasts for AROs for the periods presented:

Remainder of 2011	2012	2013	2014	2015
$ 0.6	$ 1.2	$ 1.3	$ 1.4	$ 1.5

Note 7. Investment in Evangeline

Acadian Gas, through a wholly owned subsidiary, owns an aggregate 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, including decisions by Entergy's management and regulatory approvals that may be required for Entergy to acquire Evangeline's assets.

We received our first cash distribution of $1.5 million from Evangeline in May 2011. Our share of undistributed earnings of Evangeline totaled approximately $3.7 million at June 30, 2011.

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

	Summarized Income Statement Information for the Three Months Ended					
	June 30, 2011			June 30, 2010		
	Revenues	Operating Income	Net Income	Revenues	Operating Income	Net Income
Natural Gas Pipelines & Services	$ 51.8	$ 0.9	$ 0.9	$ 51.1	$ 0.1	$ *

* Amount is negligible

	Summarized Income Statement Information for the Six Months Ended					
	June 30, 2011			June 30, 2010		
	Revenues	Operating Income	Net Income	Revenues	Operating Income	Net Income
Natural Gas Pipelines & Services	$ 84.5	$ 1.5	$ 1.5	$ 90.8	$ 0.7	$ 0.5

Note 8. Intangible Assets and Goodwill

Identifiable Intangible Assets

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

	At June 30, 2011			At December 31, 2010		
	Gross Value	Accum. Amort.	Carrying Value	Gross Value	Accum. Amort.	Carrying Value
NGL Pipelines & Services:						
Customer relationship intangibles	$ 24.6	$ (11.9)	$ 12.7	$ 24.6	$ (11.0)	$ 13.6
Contract-based intangibles	43.2	(31.9)	11.3	43.2	(29.5)	13.7
Natural Gas Pipelines & Services:						
Customer relationship intangibles	21.0	(10.9)	10.1	21.0	(10.3)	10.7
Total all segments	$ 88.8	$ (54.7)	$ 34.1	$ 88.8	$ (50.8)	$ 38.0

The following table presents amortization expense related to our intangible assets by business segment for the periods presented:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2011	2010	2011	2010
NGL Pipelines & Services	$ 1.6	$ 1.7	$ 3.3	$ 3.5
Natural Gas Pipelines & Services	0.3	0.4	0.6	0.7
Total all segments	$ 1.9	$ 2.1	$ 3.9	$ 4.2

The following table presents our forecast of amortization expense associated with existing intangible assets by business segment for the periods presented:

	Remainder of 2011	2012	2013	2014	2015
NGL Pipelines & Services	$ 3.2	$ 3.0	$ 1.7	$ 1.5	$ 1.4
Natural Gas Pipelines & Services	0.6	1.1	1.0	0.9	0.8
Total all segments	$ 3.8	$ 4.1	$ 2.7	$ 2.4	$ 2.2

In general, our intangible assets fall within two categories: customer relationships and contract-based 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.

Contract-based intangible assets represent specific commercial rights arising from discrete contractual agreements acquired in connection with the aforementioned drop down transactions.

Customer relationship intangible assets. Our customer relationship intangible assets (i) supply us with information about or access to customers and (ii) grant customers 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 June 30, 2011, the carrying value of our customer relationship intangible assets was $22.8 million.

The values assigned to our customer relationship intangible assets are being amortized to earnings using methods that closely resemble the pattern in which the economic benefits of the underlying natural resource basins from which the customers produce are estimated to be consumed or otherwise used (based on proved reserves). Our estimate of the useful life of each natural resource basin is based on a number of factors, including third-party reserve estimates, our view of the economic viability of production and exploration activities and other industry factors.

Contract-based intangible assets. At June 30, 2011, the carrying value of our contract-based intangible assets was $11.3 million. Our storage contracts related to Mont Belvieu storage and Markham NGL storage are included in our NGL Pipelines & Services segment.

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, and more frequently, if circumstances indicate it is probable that the fair value of goodwill is below its carrying amount. There have been no changes to our goodwill amounts since those reported in our 2010 Form 10-K.

Note 9. Debt Obligations

Our consolidated debt obligations consisted of the following at the dates indicated (arranged in order of maturity):

	June 30, 2011	December 31, 2010
Term Loan Agreement, variable rate, due December 2011 (4)	$ 282.3	$ 282.3
Multi-Year Revolving Credit Facility, variable rate, due October 2013 (1,3)	467.5	106.0
$400 Million Term Loan Facility, variable rate, due October 2013 (2,3)	400.0	400.0
Total principal amount of debt obligations	1,149.8	788.3
Less: Current maturities of debt (5)	(282.3)	(282.3)
Total long-term debt	$ 867.5	$ 506.0

(1) Refers to our $850.0 million multi-year revolving credit facility, which we entered into in October 2010.
(2) Refers to our $400.0 million term loan facility, which we entered into in October 2010.
(3) Collectively referred to as the “Revolving Credit and Term Loan Agreement.”
(4) Refers to our $300.0 million term loan facility, which we entered into in December 2008 in order to fund cash consideration due to EPO in connection with the DEP II drop down transaction.
(5) We expect to refinance the current maturities of our debt obligations prior to their maturity.

There have been no changes in the terms of our outstanding debt obligations since those reported in our 2010 Form 10-K.

Covenants

After giving effect to the limited waivers described below, we were in compliance with the financial covenants of our consolidated debt agreements at June 30, 2011.

Our revolving credit and term loan agreements include various operating and financial covenants, including provisions for maintaining a leverage ratio (i.e., a debt to Consolidated Adjusted EBITDA ratio (as such terms are defined in the underlying lending agreements)) of less than 5.00x as of the last day of any fiscal quarter. Principally as a result of increased capital spending on the Haynesville Extension project and working capital needs, our leverage ratio at June 30, 2011 was determined to be 5.04x, which (but for the waivers described below) would have exceeded the maximum leverage ratio allowed under our lending agreements. We expect that our leverage ratio as of September 30, 2011 will also exceed 5.00x. However, after the Haynesville Extension enters full commercial operations (expected in the fourth quarter of 2011), we anticipate that the ratio will be less than 5.00x as of December 31, 2011.

As a result of the foregoing, we and our lenders entered into limited waiver agreements on June 30, 2011 with respect to the quarterly leverage ratio covenant. The leverage ratio covenant is waived for the fiscal quarters ending June 30, 2011 and September 30, 2011. The limited waiver agreements will provide us with additional financial flexibility in light of our capital spending requirements for the Haynesville Extension natural gas pipeline project.

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 six months ended June 30, 2011:

	Range of Interest Rates Paid	**Weighted-Average Interest Rate Paid**
Multi-Year Revolving Credit Facility	2.01% to 2.16%	2.09%
$400 Million Term Loan Facility	2.26% to 2.51%	2.40%
Term Loan Agreement	1.06% to 1.26%	1.15%

Evangeline Joint Venture Debt Obligation

In March 2011, Evangeline made the final scheduled payment of $3.2 million on its subordinated note payable. Following this payment, Evangeline no longer has any debt obligations.

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.

Registration Statements and Equity Offerings

At June 30, 2011, we have two active registration statements on file with the SEC: the first covers our distribution reinvestment plan (“DRIP”), and the second covers both our employee unit purchase plan (“EUPP”) and the 2010 Plan. After taking into account limited partner units issued under our active registration statements through June 30, 2011, we may issue an additional 1,939,272 units under the DRIP, 455,459 units under the EUPP and 489,986 units under the 2010 Plan.

The following table reflects the number of common units issued and the net cash proceeds received in connection with the DRIP and EUPP during the six months ended June 30, 2011:

	Number of Common Units Issued	Net Cash Proceeds
February DRIP	10,319	$ 0.3
February EUPP	7,385	0.3
May DRIP	9,118	0.4
May EUPP	12,624	0.5
Total	39,446	$ 1.5

Net cash proceeds received from our DRIP and EUPP were used for general partnership purposes.

Unit History

The following table summarizes changes in our outstanding units since December 31, 2010:

	Common Units	Restricted Common Units
Balance, December 31, 2010	57,749,158	--
Common units issued in connection with DRIP and EUPP	39,446	--
Restricted common units issued to independent directors under our 2010 Plan	--	3,666
Conversion of restricted units to common units	3,666	(3,666)
Balance, June 30, 2011	57,792,270	--

Cash Distributions

We are required to distribute 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 any set rate per unit. Our general partner has no incentive distribution rights.

The following table presents our declared quarterly cash distribution rates with respect to the quarters indicated:

	Distribution Per Common Unit	Record Date	Payment Date
2011			
1st Quarter	$ 0.4575	04/29/2011	05/06/2011
2nd Quarter	$ 0.4600	07/29/2011	08/10/2011

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 share 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 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.

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. See Note 13 for additional information regarding these related party agreements. No capital spending for the DEP I Midstream Businesses was funded by EPO under the Omnibus Agreement during the three and six months ended June 30, 2011 and 2010.

Caverns LLC Agreement. EPO made cash contributions of $1.8 million and $3.1 million under the Caverns LLC Agreement during the three months ended June 30, 2011 and 2010, respectively. For the six months ended June 30, 2011 and 2010, EPO made cash contributions of $5.8 million and $13.1 million, respectively, under the Caverns LLC Agreement 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. Therefore, 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 $26.2 million are expected from EPO to fund these specific projects for the remainder of 2011.

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 Energy 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 $117.8 million and $30.9 million to Acadian Gas under the Amended Acadian LLC Agreement in connection with the Haynesville Extension project during the three months ended June 30, 2011 and 2010, respectively. For the six months ended June 30, 2011 and 2010, EPO made cash contributions of $175.7 million and $30.9 million, respectively, to Acadian Gas under the Amended Acadian LLC Agreement in connection with the Haynesville Extension project. For additional information regarding the Amended Acadian LLC Agreement, see "Relationship with EPO – Amended Acadian LLC Agreement" under Note 13.

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2011	2010	2011	2010
Total net income of DEP I Midstream Businesses, after special allocations	$ 15.9	$ 17.6	$ 29.2	$ 33.2
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	5.4	5.9	9.9	11.2
Add (deduct) operational measurement gains (losses) allocated to Parent	1.9	3.5	(3.4)	4.4
Less depreciation expense related to fully funded projects allocated to Parent	(1.7)	(1.6)	(3.4)	(3.1)
Net income attributable to noncontrolling interest – DEP I Midstream Businesses – Parent	$ 5.6	$ 7.8	$ 3.1	$ 12.5

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 June 30, 2011:

Balance, December 31, 2010	$ 686.7
Net income attributable to noncontrolling interest – DEP I Midstream Businesses – Parent	3.1
Contributions made by EPO to Mont Belvieu Caverns in connection with the Caverns LLC Agreement	5.8
Contributions made by EPO to Acadian Gas in connection with the Amended Acadian LLC Agreement	175.7
Other contributions made by EPO to the DEP I Midstream Businesses	11.5
Distributions to EPO by the DEP I Midstream Businesses	(7.8)
Balance, June 30, 2011	$ 875.0

For additional information regarding our agreements with EPO in connection with the DEP I drop down transaction, see "Relationship with EPO" under 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.

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 initial annualized return rate from December 8, 2008 through December 31, 2009 was 11.85%, which was 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 2010 was 12.087% and for 2011 is 12.329%. 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. Our Distribution Base has remained at $730.0 million from December 8, 2008 through June 30, 2011. EPO's Distribution Base was $452.1 million, $1.10 billion and $1.39 billion at December 8, 2008, December 31, 2010 and June 30, 2011, 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 three and six months ended June 30, 2011, EPO funded $104.5 million and $256.4 million, respectively, of expansion capital spending for the DEP II Midstream Businesses. This spending primarily relates to natural gas pipeline projects in the Barnett Shale 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 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 income of the DEP II Midstream Businesses for the three months ended June 30, 2011:

		EPO	DEP
Total net income of DEP II Midstream Businesses		$ 13.2	$ 13.2
Multiplied by each owner's Percentage Interest		77.4%	22.6%
Base earnings allocation to each owner		10.2	3.0
Additional earnings allocation to Duncan Energy Partners:			
Total distributions paid by the DEP II Midstream Businesses with respect to period	$ 43.4		
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	9.8		
Less actual distributions paid to Duncan Energy Partners with respect to period based on annualized return for period	(22.5)	(12.7)	12.7
Net loss attributable to EPO as noncontrolling interest		$ (2.5)	
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 three months ended June 30, 2010:

		EPO	DEP
Total net loss of DEP II Midstream Businesses		$ (3.6)	$ (3.6)
Multiplied by each owner's Percentage Interest		77.4%	22.6%
Base earnings allocation to each owner		(2.8)	(0.8)
Additional earnings allocation to Duncan Energy Partners:			
Total distributions paid by the DEP II Midstream Businesses with respect to period	$ 24.5		
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	5.5		
Less actual distributions paid to Duncan Energy Partners with respect to period based on annualized return for period	(22.0)	(16.5)	16.5
Net loss attributable to EPO as noncontrolling interest		$ (19.3)	
Net income attributable to Duncan Energy Partners			$ 15.7

The following table presents the allocation of net income of the DEP II Midstream Businesses for the six months ended June 30, 2011:

		EPO	DEP
Total net income of DEP II Midstream Businesses		$ 28.8	$ 28.8
Multiplied by each owner's Percentage Interest		77.4%	22.6%
Base earnings allocation to each owner		22.3	6.5
Additional earnings allocation to Duncan Energy Partners:			
Total distributions paid by the DEP II Midstream Businesses with respect to period	$ 96.2		
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	21.7		
Less actual distributions paid to Duncan Energy Partners with respect to period based on annualized return for period	(45.0)	(23.3)	23.3
Net loss attributable to EPO as noncontrolling interest		$ (1.0)	
Net income attributable to Duncan Energy Partners			$ 29.8

The following table presents the allocation of net income of the DEP II Midstream Businesses for the six months ended June 30, 2010:

		EPO	DEP
Total net income of DEP II Midstream Businesses		$ 0.8	$ 0.8
Multiplied by each owner's Percentage Interest		77.4%	22.6%
Base earnings allocation to each owner		0.6	0.2
Additional earnings allocation to Duncan Energy Partners:			
Total distributions paid by the DEP II Midstream Businesses with respect to period	$ 62.0		
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	14.0		
Less actual distributions paid to Duncan Energy Partners with respect to period based on annualized return for period	(44.1)	(30.1)	30.1
Net loss attributable to EPO as noncontrolling interest		$ (29.5)	
Net income attributable to Duncan Energy Partners			$ 30.3

The DEP II Midstream Businesses distributed an aggregate of $43.4 million and $24.5 million for the three months ended June 30, 2011 and 2010, respectively. Of these amounts, EPO received $20.9 million and $2.5 million for the three months ended June 30, 2011 and 2010, respectively. For the six months ended June 30, 2011 and 2010, the DEP II Midstream Businesses distributed an aggregate of $96.2 million and $62.0 million, respectively. EPO received $51.2 million and $17.9 million for the six months ended June 30, 2011 and 2010, respectively.

The $22.5 million and $22.0 million received by us from the DEP II Midstream Businesses with respect to the three months ended June 30, 2011 and 2010, respectively, represent approximately one-quarter of the annualized return rate for 2011 of 12.329% and 2010 of 12.087%, respectively, multiplied by our Distribution Base of $730.0 million. For the six months ended June 30, 2011 and 2010, we received $45.0 million and $44.1 million, respectively, which represents approximately one-half of each respective year's annualized return rate. As a result, we received our expected Tier I distributions for the periods indicated. Based on EPO's Distribution Base, it was entitled to $42.9 million and $29.3 million of Tier II distributions for the three months ended June 30, 2011 and 2010, respectively, of which it received $20.9 million and $2.5 million, respectively. EPO was entitled to $82.7 million and $55.9 million of Tier II distributions for the six months ended June 30, 2011 and 2010, respectively, of which it received $51.2 million and $17.9 million, respectively. No Tier III distributions were paid by the DEP II Midstream Businesses with respect to the three and six months ended June 30, 2011.

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 June 30, 2011:

Balance, December 31, 2010	$	3,072.5
Allocated loss from DEP II Midstream Businesses to EPO as Parent		(1.0)
Contributions by EPO in connection with expansion cash calls		256.4
Distributions to noncontrolling interest of subsidiary operating cash flows		(55.0)
Other general contributions from noncontrolling interest, net		3.8
Balance, June 30, 2011	$	3,276.7

For additional information regarding our agreements with EPO in connection with the DEP I or II drop down transaction, see "Relationship 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 our 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 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 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 expense transactions, provision for income taxes, the cumulative effect of changes in accounting principles and extraordinary charges. Gross operating margin is presented on a 100% basis before the allocation of earnings to noncontrolling interest.

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2011	2010	2011	2010
Revenues	$ 302.8	$ 265.2	$ 586.0	$ 555.8
Less: Operating costs and expenses	(267.8)	(245.1)	(524.8)	(512.3)
Add: Equity in income of Evangeline	0.5	--	0.8	0.2
Depreciation, amortization and accretion in operating costs and expenses (1)	52.0	51.5	102.9	99.1
Non-cash asset impairment charges included in operating costs and expenses (2)	--	--	--	1.5
Gains from asset sales and related transactions in operating costs and expenses	(0.3)	(0.1)	(0.5)	(1.0)
Total segment gross operating margin	$ 87.2	$ 71.5	$ 164.4	$ 143.3

(1) Amount is a component of "Depreciation, amortization and accretion" as presented on the Unaudited Condensed Statements of Consolidated Cash Flows.
(2) See Note 4 for additional information regarding non-cash asset impairment charges.

The following table presents a reconciliation of total segment gross operating margin to operating income and further to income before provision for income taxes for the periods presented:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2011	2010	2011	2010
Total segment gross operating margin	$ 87.2	$ 71.5	$ 164.4	$ 143.3
Adjustments to reconcile total segment gross operating margin to operating income:				
Depreciation, amortization and accretion in operating costs and expenses	(52.0)	(51.5)	(102.9)	(99.1)
Non-cash asset impairment charges included in operating costs and expenses	--	--	--	(1.5)
Gains from asset sales and related transactions in operating costs and expenses	0.3	0.1	0.5	1.0
General and administrative costs	(6.5)	(4.8)	(11.1)	(9.7)
Operating income	29.0	15.3	50.9	34.0
Interest expense	(2.9)	(3.2)	(6.0)	(6.3)
Income before provision for income taxes	$ 26.1	$ 12.1	$ 44.9	$ 27.7

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NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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

	Reportable Segments				
	Natural Gas Pipelines & Services	NGL Pipelines & Services	Petrochemical Services	Adjustments and Eliminations	Consolidated Total
Revenues from third parties:					
Three months ended June 30, 2011	$ 109.1	$ 26.9	$ 4.0	$ --	$ 140.0
Three months ended June 30, 2010	92.1	28.6	3.5	--	124.2
Six months ended June 30, 2011	222.1	54.9	6.1	--	283.1
Six months ended June 30, 2010	223.4	52.3	6.7	--	282.4
Revenues from related parties:					
Three months ended June 30, 2011	112.4	50.4	--	--	162.8
Three months ended June 30, 2010	108.1	32.9	--	--	141.0
Six months ended June 30, 2011	204.9	98.0	--	--	302.9
Six months ended June 30, 2010	204.7	68.7	--	--	273.4
Total revenues:					
Three months ended June 30, 2011	221.5	77.3	4.0	--	302.8
Three months ended June 30, 2010	200.2	61.5	3.5	--	265.2
Six months ended June 30, 2011	427.0	152.9	6.1	--	586.0
Six months ended June 30, 2010	428.1	121.0	6.7	--	555.8
Equity in income of Evangeline:					
Three months ended June 30, 2011	0.5	--	--	--	0.5
Three months ended June 30, 2010	--	--	--	--	--
Six months ended June 30, 2011	0.8	--	--	--	0.8
Six months ended June 30, 2010	0.2	--	--	--	0.2
Gross operating margin:					
Three months ended June 30, 2011	51.2	33.0	3.0	--	87.2
Three months ended June 30, 2010	37.1	31.6	2.8	--	71.5
Six months ended June 30, 2011	102.9	57.3	4.2	--	164.4
Six months ended June 30, 2010	79.6	58.5	5.2	--	143.3
Segment assets:					
At June 30, 2011	3,600.1	1,006.8	78.8	1,552.8	6,238.5
At December 31, 2010	3,527.6	996.1	80.4	807.4	5,411.5
Property, plant and equipment: (see Note 6)					
At June 30, 2011	3,580.0	982.3	78.8	1,552.8	6,193.9
At December 31, 2010	3,506.1	968.3	80.4	807.4	5,362.2
Investment in Evangeline: (see Note 7)					
At June 30, 2011	5.6	--	--	--	5.6
At December 31, 2010	6.4	--	--	--	6.4
Intangible assets: (see Note 8)					
At June 30, 2011	10.1	24.0	--	--	34.1
At December 31, 2010	10.7	27.3	--	--	38.0
Goodwill: (see Note 8)					
At June 30, 2011	4.4	0.5	--	--	4.9
At December 31, 2010	4.4	0.5	--	--	4.9

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The following table provides additional information regarding our consolidated revenues (net of adjustments and eliminations) and costs and expenses for the periods presented:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2011	2010	2011	2010
Natural Gas Pipelines & Services:				
Sales of natural gas	$ 135.4	$ 127.4	$ 256.8	$ 280.6
Natural gas transportation services	82.4	68.2	162.8	139.0
Natural gas storage services	3.7	4.6	7.4	8.5
Total segment revenues	221.5	200.2	427.0	428.1
NGL Pipelines & Services:				
Sales of NGLs	18.9	11.0	35.8	21.0
Sales of other products	7.6	4.5	14.4	8.2
NGL and related product storage services	28.8	28.8	60.1	55.9
NGL fractionation services	8.2	6.4	16.6	14.1
NGL transportation services	13.1	10.3	24.8	20.8
Other services	0.7	0.5	1.2	1.0
Total segment revenues	77.3	61.5	152.9	121.0
Petrochemical Services:				
Propylene transportation services	4.0	3.5	6.1	6.7
Total consolidated revenues	$ 302.8	$ 265.2	$ 586.0	$ 555.8
Consolidated costs and expenses:				
Operating costs and expenses:				
Cost of natural gas and NGL sales	$ 151.9	$ 134.5	$ 289.3	$ 295.7
Depreciation, amortization and accretion	52.0	51.5	102.9	99.1
Gains from asset sales and related transactions	(0.3)	(0.1)	(0.5)	(1.0)
Other operating expenses	64.2	59.2	133.1	118.5
General and administrative costs	6.5	4.8	11.1	9.7
Total consolidated costs and expenses	$ 274.3	$ 249.9	$ 535.9	$ 522.0

Changes in our revenues and operating costs and expenses period-to-period are explained in part by changes in energy commodity prices. In general, higher energy commodity prices result in an increase in our revenues attributable to the sale of NGLs and natural gas; 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 presented:

	For the Three Months Ended June 30, 2011	For the Three Months Ended June 30, 2010	For the Six Months Ended June 30, 2011	For the Six Months Ended June 30, 2010
Revenue:				
Revenues from EPO:				
Sales of natural gas	$ 33.0	$ 29.5	$ 65.8	$ 62.1
Natural gas transportation services	29.1	28.5	57.4	54.3
Natural gas storage services	--	1.0	--	1.3
Sales of NGLs	22.1	10.6	40.8	20.4
NGL and related product storage services	11.1	9.4	23.8	18.3
NGL fractionation services	8.1	6.4	16.2	14.1
NGL transportation services	9.1	6.5	17.1	15.9
Sales of natural gas – Evangeline	49.6	49.0	80.3	86.8
Natural gas transportation services – Energy Transfer Equity	0.7	0.1	1.4	0.2
NGL and related product storage services – Energy Transfer Equity	--	--	0.1	--
Total related party revenues	$ 162.8	$ 141.0	$ 302.9	$ 273.4
Operating costs and expenses:				
EPCO administrative services agreement	$ 23.3	$ 22.1	$ 44.0	$ 43.4
Expenses with EPO:				
Purchases of natural gas	30.2	15.7	54.3	29.3
Operational measurement losses (gains)	(1.9)	(3.5)	3.4	(4.4)
Other expenses with EPO	5.0	4.3	10.9	8.8
Purchases of natural gas – Nautilus	0.1	0.2	0.1	0.2
Expenses with Energy Transfer Equity:				
Purchases of natural gas	(1.0)	2.0	6.1	5.8
Operating cost reimbursements for shared facilities	(0.7)	(0.9)	(1.8)	(1.9)
Other expenses with Energy Transfer Equity	(0.4)	1.1	4.3	1.3
Total related party operating costs and expenses	$ 54.6	$ 41.0	$ 121.3	$ 82.5
General and administrative costs:				
EPCO ASA	$ 4.4	$ 3.4	$ 8.1	$ 7.5
Other related party general and administrative	0.4	(0.1)	0.7	--
Total related party general and administrative costs	$ 4.8	$ 3.3	$ 8.8	$ 7.5

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

	June 30, 2011	December 31, 2010
Accounts receivable – related parties		
EPO and affiliates	$ 54.2	$ 19.5
Energy Transfer Equity and affiliates	0.9	1.6
Total	$ 55.1	$ 21.1

Accounts payable – related parties				
EPO and affiliates	$	61.1	$	13.6
EPCO and affiliates		13.1		13.2
Energy Transfer Equity and affiliates		0.1		--
Total	$	74.3	$	26.8

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.

Relationship with EPO

One of our primary business purposes is to support the growth objectives of EPO and other affiliates of EPCO that are under common control. 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 economic interests in these assets with EPO, will result in a collaborative effort to promote their operational efficiency and maximize value. In addition, we believe our relationship with EPO provides us with a distinct benefit in the identification and execution of potential future acquisitions that are not otherwise taken by Enterprise.

At June 30, 2011, EPO beneficially 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.

Agreement and Plan of Merger with Enterprise. On April 28, 2011, we entered into an Agreement and Plan of Merger (the "Merger Agreement"), by and among Enterprise, Enterprise GP, EPD MergerCo LLC, a Delaware limited liability company and a wholly owned subsidiary of Enterprise ("MergerCo"), Duncan Energy Partners and DEP GP. At the effective time of the merger and pursuant to the Merger Agreement, MergerCo will merge with and into Duncan Energy Partners, with Duncan Energy Partners surviving the merger as a wholly owned subsidiary of Enterprise (the "DEP Merger"), and all of our common units outstanding at the effective time of the merger will be cancelled and converted into the right to receive common units representing limited partner interests in Enterprise based on an exchange rate of 1.01 Enterprise common units for each of our common units. However, in lieu of Enterprise common units, Enterprise GTM Holdings L.P. ("Enterprise GTM"), an indirect wholly owned subsidiary of Enterprise, would exchange its right to merger consideration with respect to 33,783,587 of our common units currently directly owned by it (representing approximately 58.5% of our outstanding common units) for retaining an equivalent limited partner interest in Duncan Energy Partners. No fractional Enterprise common units would be issued in the proposed DEP Merger, and our unitholders would receive cash in lieu of fractional Enterprise common units, if any.

The Audit, Conflicts and Governance ("ACG") Committee of DEP GP unanimously determined that the DEP Merger, the Merger Agreement and the transactions contemplated thereby are fair and reasonable to us and our unitholders that are unaffiliated with Enterprise, with such approval constituting "Special Approval" under our Partnership Agreement. The ACG Committee of DEP GP also recommended that the DEP Merger be approved by our unaffiliated unitholders and DEP GP's board of directors. Based on such determination, Special Approval and related recommendations, DEP GP's board of directors approved the DEP Merger and recommended that our unaffiliated unitholders vote in favor of the DEP Merger proposal. In addition, the board of directors of the general partner of Enterprise approved the transaction.

On September 7, 2011, we will host a special meeting of unitholders to consider and vote upon approval of the Merger Agreement and the DEP Merger. The Merger Agreement and the DEP Merger must be approved by the affirmative vote or consent of holders of (i) a majority of our outstanding common units and (ii) a majority of our common units owned by the Duncan unitholders unaffiliated with Enterprise that actually vote for or against such approval. In connection with the Merger Agreement, we, Enterprise and Enterprise GTM entered into a Voting Agreement, dated as of April 28, 2011 (the "Voting Agreement"), pursuant to which Enterprise GTM and Enterprise agreed to vote all of our common units owned by them or their subsidiaries in favor of the adoption of the Merger Agreement and the DEP Merger at any meeting of our unitholders, including the 33,783,587 of our common units currently directly owned by Enterprise GTM (representing approximately 58.5% of our outstanding common units). The Voting Agreement will terminate upon the termination of the Merger Agreement.

The Merger Agreement contains customary representations, warranties and covenants by each of the parties. Completion of the proposed DEP Merger is conditioned upon, among other things: (i) requisite Duncan Energy Partners' unitholder approval of the Merger Agreement and the DEP Merger as described above; (ii) applicable regulatory approvals; (iii) the absence of certain legal injunctions or impediments prohibiting the transactions; (iv) the effectiveness of a registration statement on Form S-4 with respect to the issuance by Enterprise of the Enterprise common units in connection with the DEP Merger (the Form S-4 was declared effective by the SEC on August 1, 2011); (v) the receipt of certain tax opinions; and (vi) approval for the listing of the Enterprise common units to be issued in connection with the DEP Merger on the NYSE. Subject to the satisfaction of these conditions, completion of the DEP Merger is expected to occur during the third quarter of 2011. See Note 15 for information regarding litigation matters associated with the proposed DEP Merger.

The Merger Agreement contains provisions granting both us and Enterprise the right to terminate the Merger Agreement for certain reasons, including (i) if the DEP Merger has not occurred on or before October 31, 2011 and (ii) our failure to obtain the requisite unitholder approvals as described above.

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. These amounts were subsequently repaid on January 4, 2010.

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 June 30, 2011 are summarized as follows:

§ EPO agreed to fund 100% of the post-February 5, 2007 capital expenditures incurred by South Texas NGL and Mont Belvieu Caverns with respect to certain expansion projects under construction at the time of our initial public offering;

§ EPO agreed to fund 100% of post-December 8, 2008 capital expenditures to complete the Sherman Extension natural gas pipeline (a component of our Texas Intrastate System);

§ 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 ACG Committee must approve amendments to the Omnibus Agreement when such amendments would adversely affect our unitholders.

Mont Belvieu Caverns' LLC Agreement. The Caverns LLC Agreement 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 Partners may elect to acquire a 66% share of these expansion projects from EPO within 90 days of such projects being placed in service. Effective November 2008, the Caverns LLC Agreement provides for EPO to prospectively receive a special allocation of 100% of the depreciation expense 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. Operational measurement gains and losses are created when product is moved between storage wells and are attributable to pipeline and well connection measurement variances.

For information regarding capital expenditures funded 100% by EPO under the Caverns LLC Agreement as well as operational measurement gains and losses allocated to EPO, see "Noncontrolling Interest – DEP I Midstream Businesses – Parent" under Note 11.

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 amended and restated agreements provided for (i) the acquisition by us of a 66% general partner interest in Enterprise GC, a 51% general partner interest in Enterprise Intrastate and a 51% member interest in Enterprise Texas; (ii) the payment of cash distributions by the DEP II Midstream Businesses to us and EPO in accordance with a waterfall approach; (iii) the funding of operating cash flow deficits of the DEP II Midstream Businesses in accordance with each owner's respective partner or member interest; and (iv) the election by either owner to participate in the funding of expansion capital projects of the DEP II Midstream Businesses. 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. This document includes the agreement between us and EPO regarding funding arrangements for the Haynesville Extension project. 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 $1.50 billion (including capitalized interest); therefore, we estimate that our share of such costs will approximate $990 million. In order to address our funding requirements under the Haynesville Extension project, we entered into new long-term senior unsecured credit facilities in October 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).

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 to the ASA or by other service providers. We, Enterprise 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.

- 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 its employees. We reimburse EPCO for actual direct and indirect expenses it incurs related to the operation of our assets. Likewise, our general and administrative costs include amounts paid to EPCO for administrative services, including the compensation of its 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). The following table presents a breakout of costs and expenses related to the ASA and other EPCO transactions for the periods presented:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2011	2010	2011	2010
Operating costs and expenses	$ 23.3	$ 22.1	$ 44.0	$ 43.4
General and administrative expenses	4.4	3.4	8.1	7.5
Total costs and expenses	$ 27.7	$ 25.5	$ 52.1	$ 50.9

Since the vast majority of such expenses are charged to us under the ASA 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 and Enterprise GP, Duncan Energy Partners and 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, Duncan Energy Partners and our respective general partners.

Relationship with Evangeline

Acadian Gas sold $49.6 million and $49.0 million of natural gas to Evangeline, under its natural gas purchase contract with Evangeline, during the three months ended June 30, 2011 and 2010, respectively. For the six months ended June 30, 2011 and 2010, Acadian Gas sold $80.3 million and $86.8 million, respectively, of natural gas to Evangeline. The amount of natural gas purchased by Evangeline pursuant to this contract averaged approximately 114.4 BBtus per day ("BBtus/d") and 94.5 BBtus/d during the three months ended June 30, 2011 and 2010, respectively, and 95.2 BBtus/d and 83.3 BBtus/d during the six months ended June 30, 2011 and 2010, respectively.

Relationship with Energy Transfer Equity

Enterprise has a noncontrolling ownership interest in Energy Transfer Equity that is accounted for using the equity method. Since we are under common control with Enterprise, Energy Transfer Equity is considered a related party to us. Our revenues from Energy Transfer Equity are attributable to natural gas transportation services and NGL and petrochemical storage 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 East Texas.

Enterprise Texas, a DEP II Midstream Business, is party to a lease of certain capacity rights from an ETP subsidiary with respect to a 240-mile, 24-inch diameter natural gas pipeline located in East Texas (the "Leased Pipeline"). Enterprise Texas currently utilizes a portion of this pipeline for existing services. Lease payments to ETP were approximately $1.5 million for the year ended December 31, 2010 and $0.8 million for the six months ended June 30, 2011.

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 presented:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2011	2010	2011	2010
Total net income attributable to Duncan Energy Partners L.P.	$ 22.5	$ 23.3	$ 41.8	$ 44.5
Multiplied by DEP GP ownership interest	0.7%	0.7%	0.7%	0.7%
Net income allocation to DEP GP	$ 0.2	$ 0.1	$ 0.3	$ 0.3

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2011	2010	2011	2010
Total net income attributable to Duncan Energy Partners L.P.	$ 22.5	$ 23.3	$ 41.8	$ 44.5
Less: Net income allocation to DEP GP	(0.2)	(0.1)	(0.3)	(0.3)
Net income allocation to limited partners	$ 22.3	$ 23.2	$ 41.5	$ 44.2
Basic and diluted earnings per unit:				
Net income allocation to limited partners (numerator)	$ 22.3	$ 23.2	$ 41.5	$ 44.2
Weighted-average units outstanding:				
Common units (denominator)	57.8	57.7	57.8	57.7
Basic and diluted earnings per unit	$ 0.39	$ 0.40	$ 0.72	$ 0.77

Note 15. Commitments and Contingencies

Litigation

As part of our normal business activities, we may be named as defendants in 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 fully indemnify us against losses arising from future legal proceedings.

Management has regular quarterly litigation reviews, including updates from legal counsel, to assess the possible need for accounting recognition or disclosure of these contingencies. We accrue an undiscounted liability for those contingencies where the incurrence of a loss is probable and the amount can be reasonably estimated. If a range of amounts can be reasonably estimated and no amount within the range is a better estimate than any other amount, then the minimum of the range is accrued. We do not record a contingent liability when the likelihood of loss is probable but the amount cannot be reasonably estimated or when it is believed to be only reasonably possible or remote. For contingencies where an unfavorable outcome is reasonably possible and the impact would be material, we disclose the nature of the contingency and, where feasible, an estimate of the possible loss or range of loss. We will vigorously defend the partnership in litigation matters. Based on a consideration of all relevant known facts and circumstances (including insurance coverage), we do not believe the ultimate outcome of any currently pending lawsuit against us will have a material impact on our financial statements individually or in the aggregate. See Note 16 for information regarding insurance matters.

At both June 30, 2011 and December 31, 2010, litigation accruals on an undiscounted basis of $6.8 million were recorded in our consolidated balance sheets as a component of other current liabilities. 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 additional accruals. In an effort to mitigate expenses associated with litigation, we may settle legal proceedings out of court.

Litigation related to proposed merger with Enterprise. The following information pertains to litigation filed by plaintiffs in connection with our proposed merger with Enterprise. We do not believe that any expenditures related to such matters will be material to our financial statements. We will continue to vigorously defend the partnership in these matters.

On March 8, 2011, Michael Crowley, a purported unitholder of Duncan Energy Partners, filed a complaint in the Court of Chancery of the State of Delaware, as a putative class action on behalf of the public unitholders of Duncan Energy Partners, captioned *Michael Crowley v. Duncan Energy Partners L.P., DEP Holdings, LLC, W. Randall Fowler, Bryan F. Bulawa, William A. Bruckmann, III, Larry J. Casey, Richard S. Snell, Enterprise Products Partners L.P., Enterprise Products Holdings LLC, and Enterprise Products Operating LLC* (the “Crowley Complaint”). The Crowley Complaint alleges, among other things, that the named directors of DEP GP have breached fiduciary duties in connection with Enterprise’s proposal to acquire our outstanding publicly-held common units and that we and DEP GP aided and abetted in these alleged breaches of fiduciary duties and that Enterprise, as the majority and controlling unitholder, along with EPO, have breached fiduciary duties by not acting in the minority unitholders’ best interest to ensure the transaction resulting from Enterprise’s proposal is entirely fair.

On March 11, 2011, Sanjay Israni, a purported unitholder of Duncan Energy Partners, filed a complaint in the Court of Chancery of the State of Delaware, as a putative class action on behalf of the public unitholders of Duncan Energy Partners, captioned *Sanjay Israni v. Duncan Energy Partners L.P., DEP Holdings, LLC, Enterprise Products Partners L.P., Enterprise Product Holdings LLC, Enterprise Production Operating LLC, W. Randall Fowler, Bryan F. Bulawa, William A. Bruckmann, III, Larry J. Casey, and Richard S. Snell* (the “Israni Complaint II”). The Israni Complaint II alleges, among other things, that the named directors of DEP GP have breached fiduciary duties in connection with Enterprise’s proposal to acquire our outstanding publicly-held common units and that we along with all of the other named defendants aided and abetted in these alleged breaches of fiduciary duties.

On March 28, 2011, Michael Rubin, a purported unitholder of Duncan Energy Partners, filed a complaint in the Court of Chancery of the State of Delaware, as a putative class action on behalf of the public unitholders of Duncan Energy Partners, captioned *Michael Rubin v. Duncan Energy Partners L.P., DEP Holdings, LLC, W. Randall Fowler, Bryan F. Bulawa, William A. Bruckmann, III, Larry J. Casey, Richard S. Snell, Enterprise Products Partners L.P., Enterprise Products Holdings LLC, and Enterprise Products Operating LLC* (the "Rubin Complaint"). The Rubin Complaint alleges, among other things, that the named directors of DEP GP have breached fiduciary duties in connection with Enterprise's proposal to acquire our outstanding publicly-held common units, that we and DEP GP aided and abetted in these alleged breaches of fiduciary duties and that Enterprise, as the majority and controlling unitholder, along with EPO, have breached fiduciary duties by not acting in the best interests of the minority unitholders to ensure the transaction resulting from Enterprise's proposal is entirely fair.

On April 5, 2011, the plaintiffs in the Crowley Complaint, the Israni Complaint II, and the Rubin Complaint filed a Proposed Order of Consolidation and Appointment of Lead Counsel in the Court of Chancery of the State of Delaware. The court granted that order on the same day consolidating the three actions into a single consolidated action, captioned *In re Duncan Energy Partners L.P. Unitholders Litigation*. On June 3, 2011 the Delaware plaintiffs filed a consolidated amended complaint which alleges, among other things, breach of express and implied contractual duties contained in our partnership agreement by DEP GP and the named directors of DEP GP and that all defendants have aided and abetted these alleged breaches. The consolidated amended complaint also alleges that the defendants failed to provide full and fair disclosures regarding the proposed transaction.

On March 7, 2011, Merle Davis, a purported unitholder of Duncan Energy Partners, filed a petition in the 269th District Court of Harris County, Texas, as a putative class action on behalf of the unitholders of Duncan Energy Partners, captioned *Merle Davis, on Behalf of Himself and All Others Similarly Situated v. Duncan Energy Partners L.P., W. Randall Fowler, Bryan F. Bulawa, William A. Bruckmann, III, Larry J. Casey, Richard S. Snell, DEP Holdings, LLC, and Enterprise Products Partners L.P.* (the "Davis Petition"). The Davis Petition alleges, among other things, that Enterprise and the named directors of DEP GP have breached fiduciary duties in connection with Enterprise's proposal to acquire our outstanding publicly-held common units and that we and Enterprise aided and abetted in these alleged breaches of fiduciary duties.

On March 9, 2011, Donald Weilersbacher, a purported unitholder of Duncan Energy Partners, filed a petition in the 334th District Court of Harris County, Texas, as a putative class action on behalf of the unitholders of Duncan Energy Partners, captioned *Donald Weilersbacher, on Behalf of Himself and All Others Similarly Situated v. Duncan Energy Partners L.P., Enterprise Products Partners L.P., DEP Holdings, LLC, W. Randall Fowler, Bryan F. Bulawa, William A. Bruckmann, III, Larry J. Casey, and Richard S. Snell* (the "Weilersbacher Petition"). The Weilersbacher Petition alleges, among other things, that the named directors of DEP GP have breached fiduciary duties in connection with Enterprise's proposal to acquire our outstanding publicly-held common units and that Enterprise aided and abetted in these alleged breaches of fiduciary duties.

On March 17, 2011, the plaintiffs in the Davis Petition and the Weilersbacher Petition filed a motion and proposed Order for Consolidation of Related Actions, Appointment of Interim Co-Lead Counsel, and Order Compelling Limited Expedited Discovery. Plaintiffs and defendants subsequently agreed to postpone discovery until after the plaintiffs file a consolidated petition. On March 28, 2011, the plaintiffs filed an amended motion and proposed Order for Consolidation of Related Actions and Appointment of Interim Co-Lead Counsel. On May 4, 2011, the court entered an order consolidating the cases and appointing interim lead counsel. On May 11, 2011, plaintiffs filed their consolidated petition. On June 23, 2011, the plaintiffs filed a Notice of Nonsuit Without Prejudice and the cases were dismissed without prejudice.

DUNCAN ENERGY PARTNERS L.P.
NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

On July 5, 2011, Merle Davis and Donald Weilersbacher, purported unitholders of Duncan Energy Partners, filed a complaint in the United States District Court of the Southern District of Texas, Houston Division, as a putative class action on behalf of the unitholders of Duncan Energy Partners, captioned *Merle Davis and Donald Weilersbacher, on Behalf of Themselves and All Others Similarly Situated vs. Duncan Energy Partners, L.P., W. Randall Fowler, Bryan F. Bulawa, William A. Bruckmann, III, Larry J. Casey, Richard Snell, DEP Holdings, LLC, and Enterprise Products Partners L.P*. (the "Davis/Weilersbacher Federal Complaint"). The Davis/Weilersbacher Federal Complaint alleged, among other things, that we, DEP GP and the named directors of DEP GP breached express and implied contractual duties in connection with Enterprise's proposal to acquire our outstanding publicly held common units, that all defendants aided and abetted in these alleged breaches, and that we and Enterprise violated Section 14(a) and Section 20(a) of the Exchange Act.

On August 3, 2011, John Rinker and Arthur H. Speier, purported unitholders of Duncan Energy Partners, filed a complaint in the United States District Court of the Southern District of Texas, Houston Division, as a putative class action on behalf of the unitholders of Duncan Energy Partners, captioned *John Rinker and Arthur H. Speier, on Behalf of Themselves and All Others Similarly Situated v. Duncan Energy Partners L.P., DEP Holdings, LLC, W. Randall Fowler, Bryan F. Bulawa, William A. Bruckmann, III, Larry J. Casey, Richard S. Snell and Enterprise Products Partners L.P.* The Rinker/Speier complaint alleges, among other things, that we, DEP GP and the named directors of DEP GP breached express and implied contractual duties in connection with Enterprise's proposal to acquire our outstanding publicly held common units, that all defendants aided and abetted in these alleged breaches, and that we and Enterprise violated Section 14(a) and Section 20(a) of the Exchange Act.

Redelivery Commitments

We store natural gas, NGLs and certain petrochemicals that are owned by third parties. In accordance with the underlying agreements, we are generally required to redeliver such volumes to the owners on demand. At June 30, 2011, we had approximately 18.4 million barrels of NGL and petrochemical products and 4.0 TBtus of natural gas in our custody that were owned by third parties. We maintain insurance coverage related to such volumes that we believe is consistent with our exposures. See Note 16 for information regarding insurance matters.

Regulatory Matters

Responding to scientific reports regarding threats posed by global warming, the U.S. Congress has considered legislation to reduce emissions of greenhouse gases. In addition, some states (e.g., California and New Mexico) have individually or in regional cooperation, imposed restrictions on greenhouse gas emissions under various policies and approaches, including establishing a cap on emissions, requiring efficiency measures, or providing incentives for pollution reduction, use of renewable energy, or use of fuels with lower carbon content.

The U.S. Environmental Protection Agency ("EPA") has taken action under the federal Clean Air Act ("CAA") to regulate greenhouse gas emissions. In November 2010, the EPA finalized rules expanding its Mandatory Greenhouse Gas Reporting Rule, originally promulgated in October 2009, to be applicable to the oil and natural gas industry, including certain onshore oil and natural gas production activities, which may affect certain of our existing or future operations and require the inventory and reporting of emissions. In addition, the EPA has taken the position that existing CAA provisions require an assessment of greenhouse gas emissions within the permitting process for certain large new or modified stationary sources under the EPA's Prevention of Significant Deterioration and Title V permit programs beginning in 2011. Facilities triggering permit requirements may be required to reduce greenhouse gas emissions consistent with "best available control technology" standards if deemed to be cost-effective.

These or other federal, regional and state measures could increase the operating and compliance costs of our pipelines, fractionation plants and other facilities, and could by affecting the price of, or reducing the demand for, fossil fuels or providing competitive advantages to competing fuels and energy sources, adversely affect market demand or pricing for our products or products served by our midstream infrastructure. In addition, there have been several court cases implicating greenhouse gas emissions and climate change issues that could establish precedent that may indirectly affect our business, customers or the energy sector generally.

Any of these climate change legislative or judicial initiatives or developments could have a material impact on our financial statements; however, we are unable to provide a range of estimated future costs due to the extreme uncertainty of such matters. There is considerable public and private debate over global warming and the environmental effects of greenhouse gas emissions.

Contractual Obligations

Scheduled maturities of long-term debt. Amounts owed under our debt agreements have increased since December 31, 2010 primarily due to borrowings to fund construction costs of the Haynesville Extension.

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 2010 Form 10-K.

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 $3.3 million and $3.2 million during the three months ended June 30, 2011 and 2010, respectively, and $6.3 million and $6.5 million during the six months ended June 30, 2011 and 2010, respectively.

Purchase obligations. There have been no material changes in our consolidated purchase obligations since those reported in our 2010 Form 10-K, except for short-term payment obligations relating to capital projects initiated by us. 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 $285.3 million at December 31, 2010 to $441.3 million at June 30, 2011. At June 30, 2011, these commitments primarily relate to the Haynesville Extension and projects on the Texas Intrastate System (e.g., Eagle Ford Shale expansion projects).

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 similar arrangements. As of June 30, 2011, claims against us totaled approximately $0.1 million. 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 impact on our consolidated financial statements from such disputes is remote. Accordingly, accruals for loss contingencies related to these matters have not been reflected in our consolidated financial statements.

Commitments under Equity Compensation Plans of EPCO

In accordance with our agreements with EPCO, we reimburse EPCO for our share of its compensation expense associated with certain employees who perform management, administrative and operating functions for us (see Note 13). See Note 3 for additional information regarding accounting for equity awards.

Note 16. Significant Risks and Uncertainties

Insurance Matters

We participate as a named insured in EPCO's insurance program, which provides us with property damage, business interruption and other insurance coverage, 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 may not fully cover every type of damage, interruption or other loss that might occur. If we were to incur a significant loss for which we were not fully insured, it could have a material impact on our financial position, results of operations and cash flows. In addition, there may be a timing difference between amounts we are required to pay in connection with a loss and amounts we receive from insurance as reimbursement. Any event that materially interrupts the revenues generated by our consolidated operations, or other losses that require us to make material 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.

From a financial accounting perspective, we expense losses up to our deductible amount, which can range from $5.0 million to $75.0 million depending on the nature of the loss (windstorm or non-windstorm) and the assets involved (onshore or offshore). With respect to property damage insurance claims in excess of our deductible, we record a claim receivable from our insurers for our actual costs to repair the asset (or the carrying value of damaged assets we elect not to repair) when the recovery of such amounts is probable. To the extent that any of our property damage claims are later judged not recoverable, such amounts are expensed. If property damage insurance proceeds exceed our claim receivable, such excess amount is recognized as income (a gain) when either the non-refundable cash is received or we have a binding settlement agreement with a carrier that clearly states that the payment will be made. With respect to business interruption insurance claims, we recognize income only when we receive non-refundable cash proceeds from insurers.

February 2011 West Storage Incident. On February 8, 2011, we experienced a NGL release and fire at the West Storage location of our Mont Belvieu, Texas underground storage facility. West Storage consists of ten underground salt dome storage caverns with a storage capacity of approximately 15 MMBbls. As a result of reconfiguring certain storage-related assets, we have restored most of the receipt and delivery capability we had prior to the incident; however, our West Storage location and associated underground storage wells remain partially non-operative at this time. Remaining repairs to this location are underway and are expected to be completed in stages by early 2012. Our insurance deductible for such property damage events was $5.0 million, which expense was recognized in the first quarter of 2011. Based on current information, we estimate that the total cost of repairs and other rebuilding activities related to this incident will approximate $150 million.

Our Mont Belvieu, Texas underground storage facility is owned by Mont Belvieu Caverns, which is part of the DEP I Midstream Businesses. We own 66% of the member interests of Mont Belvieu Caverns and EPO owns the remaining 34%. Prior to the receipt of insurance recoveries for this incident anticipated to occur in 2012 and 2013, the initial funding of the repairs and other rebuilding projects is expected to be made by us and EPO in accordance with our ownership interests in Mont Belvieu Caverns.   We expect to fund our share of such costs through borrowings under the Multi-Year Revolving Credit Facility.

At June 30, 2011, we had $37.3 million of estimated property damage insurance claims outstanding associated with the fire at West Storage, which is included in "Other assets" on our Unaudited Condensed Consolidated Balance Sheets.

Interest Rate Risk

We are exposed to changes in interest rates charged on our variable rate debt obligations. We cannot predict the costs of refinancing, at maturity, our existing credit facilities or the costs of new credit agreements. The inability to refinance or enter into new credit arrangements with favorable terms could impede our ability to fund capital requirements or to make distributions on our common units.

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 periods presented:

	For the Six Months Ended June 30,	
	2011	2010
Decrease (increase) in:		
Accounts receivable - trade	$ (2.6)	$ (9.9)
Accounts receivable - related parties	(10.1)	(19.2)
Inventories	(10.1)	(2.5)
Prepaid and other current assets	(5.7)	(3.9)
Other assets	(37.3)	--
Increase (decrease) in:		
Accounts payable – trade	1.0	6.0
Accounts payable – related parties	49.3	3.2
Accrued product payables	(9.6)	2.4
Other current liabilities	6.4	2.4
Net effect of changes in operating accounts	$ (18.7)	$ (21.5)

We incurred liabilities for construction in progress that had not been paid at June 30, 2011 and December 31, 2010 of $134.2 million and $76.9 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 presented:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2011	2010	2011	2010
DEP I Midstream Businesses	$ 11.5	$ 10.2	$ 22.7	$ 20.2
DEP II Midstream Businesses	41.6	41.2	82.2	78.6
Other	0.8	0.9	1.5	1.7
Total	$ 53.9	$ 52.3	$ 106.4	$ 100.5

See Note 11 for information regarding cash amounts attributable to noncontrolling interests.

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

For the three and six months ended June 30, 2011 and 2010.

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 in our annual report on Form 10-K for the year ended December 31, 2010, as filed on March 1, 2011 (the "2010 Form 10-K"). Our financial statements have been prepared in accordance with generally accepted accounting principles ("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" mean the business and operations of Enterprise Products Partners L.P. and its consolidated subsidiaries. Enterprise 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." Enterprise is managed by its general partner, Enterprise Products Holdings LLC ("Enterprise GP"), which is a wholly owned subsidiary of Dan Duncan LLC, a Delaware limited liability company. References to "EPO" mean Enterprise Products Operating LLC, which is a wholly owned subsidiary of Enterprise and its consolidated subsidiaries, through which Enterprise conducts substantially all of its business. EPO beneficially owns 100% of DEP GP and currently owns 58.5% of our common units. Enterprise consolidates our financial statements with its own.

On April 28, 2011, we and our general partner entered into a definitive merger agreement with Enterprise, Enterprise GP and certain of their subsidiaries. See "Significant Recent Developments" within this Item 2 for information regarding the proposed merger with Enterprise.

The membership interests of Dan Duncan LLC are owned of record by a voting trust, the current trustees ("DD LLC Trustees") of which are: (i) Randa Duncan Williams, who is also a director of Enterprise GP; (ii) Dr. Ralph S. Cunningham, who is also a director and the Chairman of Enterprise GP and one of three managers of Dan Duncan LLC; and (iii) Richard H. Bachmann, who is also a director of Enterprise GP and one of three managers of Dan Duncan LLC.

References to "EPCO" mean Enterprise Products Company and its privately held affiliates. A majority of the outstanding voting capital stock of EPCO is owned of record by a voting trust, the current trustees ("EPCO Trustees") of which 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 and Chief Executive Officer ("CEO") of EPCO. Ms. Williams, Dr. Cunningham and Mr. Bachmann are also currently directors of EPCO.

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. (NYSE: ETE) and its consolidated subsidiaries, which include Energy Transfer Partners, L.P. ("ETP") and Regency Energy Partners LP ("RGNC"). The general partner of Energy Transfer Equity is LE GP, LLC ("LE GP"). Enterprise owns noncontrolling interests in Energy Transfer Equity, which it accounts for using the equity method of accounting.

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
Bcf	= billion cubic feet

Cautionary Note Regarding Forward-Looking Statements

This discussion contains various forward-looking statements and information 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 detail under Item 1A "Risk Factors" included in our 2010 Form 10-K. 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 in September 2006 and did not own any assets prior to February 5, 2007, which was the date we completed our initial public offering and acquired controlling interests in the DEP I Midstream Businesses from EPO. 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 under common control. We are engaged in the business of (i) natural gas liquids, or NGLs, transportation, fractionation and marketing; (ii) storage of NGL, petrochemical and refined 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: 11,201 miles of natural gas, NGL and petrochemical pipelines; two NGL fractionation facilities; approximately 17.3

MMBbls of leased NGL storage capacity; 8.1 Bcf of leased natural gas storage capacity; and 34 underground salt dome caverns with approximately 100 MMBbls of NGL and related product 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.

We have three reportable business segments: (i) Natural Gas Pipelines & Services; (ii) NGL 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.

At June 30, 2011, we are owned 99.3% by our limited partners and 0.7% by our general partner, DEP GP. EPO beneficially owned approximately 58.5% of our limited partner interests and 100% of DEP GP. On April 28, 2011, we and our general partner entered into a definitive merger agreement with Enterprise, Enterprise GP and certain of their subsidiaries. See "Significant Recent Developments" within this Item 2 for information regarding the proposed merger with Enterprise.

We, DEP GP, EPO, Enterprise, Enterprise GP, 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 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report for information regarding the ASA and related party matters.

Our relationship with EPO is one of our principal business advantages. 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 economic interests in these assets with EPO, will result in a collaborative effort to promote their operational efficiency and maximize value. In addition, we believe our relationship with EPO provides us with a distinct benefit in the identification and execution of potential future acquisitions that are not otherwise taken by Enterprise. See Note 13 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report for additional information regarding our relationship with Enterprise, EPO and EPCO.

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.

  See "Significant Recent Developments" within this Item 2 for information regarding a February 2011 NGL release and fire at the West Storage location of our Mont Belvieu, Texas underground storage facility.

§ 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 approximately 1.1 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 central and southern 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 1.8 Bcf/d of natural gas from the Haynesville area through a 270-mile pipeline that will connect with our existing Acadian Gas system. The Haynesville Extension is expected to be completed in September 2011.

The total budgeted cost of the Haynesville Extension is approximately $1.50 billion (including capitalized interest). In June 2010, we agreed to fund 66% of the Haynesville Extension project costs and EPO agreed to fund the remaining 34% of such expenditures; therefore, we estimate that our share of such costs will approximate $990 million. In order to fund our capital spending requirements under the Haynesville Extension project, we entered into 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 debt obligations, see Note 9 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report.

§ Lou-Tex Propylene owns a 267-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 1,185-mile NGL pipeline system located in South Texas; and (iii) 1,096 miles of natural gas gathering pipelines located in South and West Texas. Enterprise GC's natural gas gathering pipelines include: (i) the 262-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 174-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 6,653-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 pipeline system and the Wilson storage facility, 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. 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 supply basin located in South Texas. We are in the process of expanding this system's natural gas gathering and transportation capabilities as well as increasing our natural gas storage capacity 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 (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 initial annualized return rate from December 8, 2008 through December 31, 2009 was 11.85%, which was 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 2010 was 12.087% and for 2011 is 12.329%.

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 DEP II Midstream Business. 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.

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 six months ended June 30, 2011 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. are the cash distributions it receives from the DEP I and DEP II Midstream Businesses. The primary cash requirements of Duncan Energy Partners are for general and administrative costs, debt service 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 general 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 June 30,		For the Six Months Ended June 30,	
	2011	2010	2011	2010
Selected income statement information:				
Equity in income - DEP I Midstream Businesses	$ 10.4	$ 11.7	$ 19.2	$ 22.0
Equity in income - DEP II Midstream Businesses	$ 15.7	$ 15.7	$ 29.8	$ 30.3
General and administrative costs	$ 0.7	$ 0.9	$ 1.2	$ 1.5
Interest expense	$ 2.9	$ 3.2	$ 6.0	$ 6.3
Net income attributable to partners	$ 22.5	$ 23.3	$ 41.8	$ 44.5
Selected balance sheet information at each period end:				
Investments in DEP I Midstream Businesses	$ 1,222.0	$ 597.6	$ 1,222.0	$ 597.6
Investments in DEP II Midstream Businesses	$ 662.5	$ 696.0	$ 662.5	$ 696.0
Total debt principal outstanding	$ 1,149.8	$ 537.3	$ 1,149.8	$ 537.3
Partners' equity	$ 754.1	$ 760.4	$ 754.1	$ 760.4

The following table presents the amount of distributions paid by each group of businesses with respect to each period:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2011	2010	2011	2010
Distributions paid to Duncan Energy Partners L.P. with respect to each period from:				
DEP I Midstream Businesses	$ 5.3	$ 7.1	$ 15.6	$ 27.0
DEP II Midstream Businesses	$ 22.5	$ 22.0	$ 45.0	$ 44.1

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 for 2010 was 12.087% and increases by 2.0% on January 1 of each year. As a result, the annualized return rate for 2011 is 12.329%. 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. Our Distribution Base has remained at $730.0 million from December 8, 2008 through June 30, 2011. EPO's Distribution Base was $452.1 million, $1.10 billion and $1.39 billion at December 8, 2008, December 31, 2010 and June 30, 2011, 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 three and six months ended June 30, 2011, EPO funded $104.5 million and $256.4 million, respectively, of expansion capital spending of the DEP II Midstream Businesses. This spending primarily relates to natural gas pipeline projects in the Barnett Shale and ongoing expansions of our pipeline network in the Eagle Ford Shale region. Although we have not yet participated in the expansion capital project spending of the DEP II Midstream Businesses, we may elect to invest in existing or future expansion projects at a later date.

The $22.5 million and $22.0 million received by us from the DEP II Midstream Businesses with respect to the three months ended June 30, 2011 and 2010, respectively, represent approximately one-quarter of the annualized return rate for 2011 of 12.329% and 2010 of 12.087%, respectively, multiplied by our Distribution Base of $730.0 million. For the six months ended June 30, 2011 and 2010, we received $45.0 million and $44.1 million, respectively, which represents approximately one-half of each respective year's annualized return rate. As a result, we received our expected Tier I distributions for the periods indicated. Based on EPO's Distribution Base, it was entitled to $42.9 million and $29.3 million of Tier II distributions for the three months ended June 30, 2011 and 2010, respectively, of which it received $20.9 million and $2.5 million, respectively. EPO was entitled to $82.7 million and $55.9 million of Tier II distributions for the six months ended June 30, 2011 and 2010, respectively, of which it received $51.2 million and $17.9 million, respectively. No Tier III distributions were paid by the DEP II Midstream Businesses with respect to the three and six months ended June 30, 2011.

Net income (or loss) of the DEP II Midstream Businesses is first allocated to us and EPO based on each entity's Percentage Interest and then in a manner that in part follows the cash distributions paid by (or contributions made to) each 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 additional information regarding the allocation of net income (or loss) of the DEP II Midstream Businesses, see Note 11 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report.

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 significant developments since January 1, 2011 through the date of this filing (August 9, 2011), 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.

Agreement and Plan of Merger with Enterprise

On April 28, 2011, we entered into an Agreement and Plan of Merger (the "Merger Agreement"), by and among Enterprise, Enterprise GP, EPD MergerCo LLC, a Delaware limited liability company and a wholly owned subsidiary of Enterprise ("MergerCo"), Duncan Energy Partners and DEP GP. At the effective time of the merger and pursuant to the Merger Agreement, MergerCo will merge with and into Duncan Energy Partners, with Duncan Energy Partners surviving the merger as a wholly owned subsidiary of Enterprise (the "DEP Merger"), and all of our common units outstanding at the effective time of the merger will be cancelled and converted into the right to receive common units representing limited partner interests in Enterprise based on an exchange rate of 1.01 Enterprise common units for each of our common units. However, in lieu of Enterprise common units, Enterprise GTM Holdings L.P. ("Enterprise GTM"), an indirect wholly owned subsidiary of Enterprise, would exchange its right to merger consideration with respect to 33,783,587 of our common units currently directly owned by it (representing approximately 58.5% of our outstanding common units) for retaining an equivalent limited partner interest in Duncan Energy Partners. No fractional Enterprise common units would be issued in the proposed DEP Merger, and our unitholders would receive cash in lieu of fractional Enterprise common units, if any.

The ACG Committee of DEP GP unanimously determined that the DEP Merger, the Merger Agreement and the transactions contemplated thereby are fair and reasonable to us and our unitholders that are unaffiliated with Enterprise, with such approval constituting "Special Approval" under our partnership agreement. The ACG Committee of DEP GP also recommended that the DEP Merger be approved by our unaffiliated unitholders and DEP GP's board of directors. Based on such determination, Special Approval and related recommendations, DEP GP's board of directors approved the DEP Merger and recommended that our unaffiliated unitholders vote in favor of the DEP Merger proposal. In addition, the board of directors of the general partner of Enterprise approved the transaction.

On September 7, 2011, we will host a special meeting of unitholders to consider and vote upon approval of the Merger Agreement and the DEP Merger. The Merger Agreement and the DEP Merger must be approved by the affirmative vote or consent of holders of (i) a majority of our outstanding common units and (ii) a majority of our common units owned by the Duncan unitholders unaffiliated with Enterprise that actually vote for or against such approval. In connection with the Merger Agreement, we, Enterprise and Enterprise GTM entered into a Voting Agreement, dated as of April 28, 2011 (the "Voting Agreement"), pursuant to which Enterprise GTM and Enterprise agreed to vote all of our common units owned by them or their subsidiaries in favor of the adoption of the Merger Agreement and the DEP Merger at any meeting of our unitholders, including the 33,783,587 of our common units currently directly owned by Enterprise GTM (representing approximately 58.5% of our outstanding common units). The Voting Agreement will terminate upon the termination of the Merger Agreement.

The Merger Agreement contains customary representations, warranties and covenants by each of the parties. Completion of the DEP Merger is conditioned upon, among other things: (i) requisite Duncan Energy Partners' unitholder approval of the Merger Agreement and the DEP Merger as described above; (ii) applicable regulatory approvals; (iii) the absence of certain legal injunctions or impediments prohibiting the transactions; (iv) the effectiveness of a registration statement on Form S-4 with respect to the issuance by Enterprise of the Enterprise common units in connection with the DEP Merger (the Form S-4 was declared effective by the SEC on August 1, 2011); (v) the receipt of certain tax opinions; and (vi) approval for the listing of the Enterprise common units to be issued in connection with the DEP Merger on the NYSE. Subject to the satisfaction of these conditions, completion of the DEP Merger is expected to occur during the third quarter of 2011. See Note 15 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report for information regarding litigation matters associated with the proposed DEP Merger.

The Merger Agreement contains provisions granting both us and Enterprise the right to terminate the Merger Agreement for certain reasons, including (i) if the DEP Merger has not occurred on or before October 31, 2011 and (ii) our failure to obtain the requisite unitholder approvals as described above.

Incident at Mont Belvieu Storage Facility

On February 8, 2011, we experienced a NGL release and fire at the West Storage location of our Mont Belvieu, Texas underground storage facility. West Storage consists of ten underground salt dome storage caverns with a storage capacity of approximately 15 MMBbls. As a result of reconfiguring certain storage-related assets, we have restored most of the receipt and delivery capability we had prior to the incident; however, our West Storage location and associated underground storage wells remain partially non-operative at this time. Remaining repairs to this location are underway and are expected to be completed in stages by early 2012. Our insurance deductible for such property damage events was $5.0 million, which expense was recognized in the first quarter of 2011.

Based on current information, we estimate that the total cost of repairs and other rebuilding activities related to this incident will approximate $150 million. We participate as a named insured in EPCO's insurance program, which provides us with property damage, business interruption and other insurance coverage, the scope and amounts of which we believe are customary and prudent for the nature and extent of our operations. See Note 16 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report for information regarding insurance matters.

Our Mont Belvieu, Texas underground storage facility is owned by Mont Belvieu Caverns, which is part of the DEP I Midstream Businesses. We own 66% of the member interests of Mont Belvieu Caverns and EPO owns the remaining 34%. Prior to the receipt of insurance recoveries for this incident anticipated to occur in 2012 and 2013, the initial funding of the repairs and other rebuilding projects is expected to be made by us and EPO in accordance with our ownership interests in Mont Belvieu Caverns. We expect to fund our share of such costs through borrowings under the Multi-Year Revolving Credit Facility.

Expansion of Armstrong Fractionation Facility Completed

In January 2011, we completed the expansion of our Armstrong NGL fractionation facility, thus enabling us to accommodate increased NGL volumes from the Eagle Ford Shale supply basin. The expansion increased NGL fractionation capacity at Armstrong from 13 MBPD to 17 MBPD. The cost of this Enterprise GC (part of the DEP II Midstream Businesses) project was funded entirely by EPO.

Results of Operations

Selected Volumetric Data

The following table presents average throughput and fractionation volumes for our principal pipelines and facilities. 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 June 30,		For the Six Months Ended June 30,	
	2011	2010	2011	2010
Natural Gas Pipelines & Services:				
Natural gas throughput volumes (BBtus/d)				
Texas Intrastate System	4,083	3,866	3,982	3,802
Acadian Gas System:				
Transportation volumes	415	451	459	430
Sales volumes (1)	362	337	345	328
	4,860	4,654	4,786	4,560
NGL Pipelines & Services:				
NGL throughput volumes (MBPD)				
South Texas NGL System - Pipelines	134	112	131	116
NGL fractionation volumes (MBPD)				
South Texas NGL System - Shoup and Armstrong fractionators	84	66	86	74
Petrochemical Services:				
Propylene throughput volumes (MBPD)				
Lou-Tex Propylene Pipeline	22	24	18	22
Sabine Propylene Pipeline	13	13	12	12
Total propylene throughput volumes	35	37	30	34

(1) Includes average net sales volumes for Evangeline of 56.6 BBtus/d and 46.8 BBtus/d for the three months ended June 30, 2011 and 2010, respectively. For the six months ended June 30, 2011 and 2010, net sales volumes for Evangeline were 47.1 BBtus/d and 41.3BBtus/d, respectively.

Comparison of Consolidated Results of Operations

The following table summarizes key components of our results of operations for the periods presented (dollars in millions):

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2011	2010	2011	2010
Revenues	$ 302.8	$ 265.2	$ 586.0	$ 555.8
Operating costs and expenses	267.8	245.1	524.8	512.3
General and administrative costs	6.5	4.8	11.1	9.7
Equity in income of Evangeline	0.5	--	0.8	0.2
Operating income	29.0	15.3	50.9	34.0
Interest expense	2.9	3.2	6.0	6.3
Net income	25.6	11.8	43.9	27.5
Net loss (income) attributable to noncontrolling interest:				
DEP I Midstream Businesses – Parent	(5.6)	(7.8)	(3.1)	(12.5)
DEP II Midstream Businesses – Parent	2.5	19.3	1.0	29.5
Net income attributable to partners	22.5	23.3	41.8	44.5

For information regarding amounts attributable to 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 as follows for the periods presented (dollars in millions):

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2011	2010	2011	2010
Natural Gas Pipelines & Services	$ 51.2	$ 37.1	$ 102.9	$ 79.6
NGL Pipelines & Services	33.0	31.6	57.3	58.5
Petrochemical Services	3.0	2.8	4.2	5.2
Total segment gross operating margin	$ 87.2	$ 71.5	$ 164.4	$ 143.3

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 presented (dollars in millions):

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2011	2010	2011	2010
Natural Gas Pipelines & Services:				
Sales of natural gas	$ 135.4	$ 127.4	$ 256.8	$ 280.6
Natural gas transportation services	82.4	68.2	162.8	139.0
Natural gas storage services	3.7	4.6	7.4	8.5
Total segment revenues	221.5	200.2	427.0	428.1
NGL Pipelines & Services:				
Sales of NGLs	18.9	11.0	35.8	21.0
Sales of other products	7.6	4.5	14.4	8.2
NGL and related product storage services	28.8	28.8	60.1	55.9
NGL fractionation services	8.2	6.4	16.6	14.1
NGL transportation services	13.1	10.3	24.8	20.8
Other services	0.7	0.5	1.2	1.0
Total segment revenues	77.3	61.5	152.9	121.0
Petrochemical Services:				
Propylene transportation services	4.0	3.5	6.1	6.7
Total consolidated revenues	$ 302.8	$ 265.2	$ 586.0	$ 555.8

Comparison of the Three Months Ended June 30, 2011 with the Three Months Ended June 30, 2010

Revenues for the second quarter of 2011 were $302.8 million compared to $265.2 million for the second quarter of 2010, a $37.6 million quarter-to-quarter increase. Consolidated revenues from sales of natural gas increased $8.0 million quarter-to-quarter primarily due to higher sales prices during the second quarter of 2011 compared to the second quarter of 2010. Revenues from sales of NGLs increased $7.9 million quarter-to-quarter attributable to both higher sales prices and volumes during the second quarter of 2011 compared to the second quarter of 2010. Consolidated revenues from the sale of other products increased $3.1 million quarter-to-quarter primarily due to higher sales volumes.

In the aggregate, consolidated revenues from the provision of services increased $18.6 million quarter-to-quarter. Revenues from natural gas transportation and storage services increased $13.3 million quarter-to-quarter primarily due to higher firm capacity reservation revenues and throughput volumes and fees on our Texas Intrastate System. Increased natural gas production volumes from the Eagle Ford Shale supply basin resulted in stronger demand for our natural gas transportation services during the second quarter of 2011 compared to the same period last year. Consolidated revenues from our NGL-related services increased $4.8 million quarter-to-quarter primarily due to higher NGL fractionation and pipeline transportation volumes on our South Texas NGL System. Revenues from propylene transportation services increased $0.5 million quarter-to-quarter primarily due to higher deficiency fee revenues on our Lou-Tex Propylene Pipeline during the second quarter of 2011 compared to the second quarter of 2010.

Operating costs and expenses were $267.8 million for the second quarter of 2011 compared to $245.1 million for second quarter of 2010, a $22.7 million quarter-to-quarter increase. Costs related to natural gas and NGL sales increased $17.4 million quarter-to-quarter primarily due to higher sales volumes and energy commodity prices during the second quarter of 2011 compared to the second quarter of 2010. Operating costs and expenses attributable to operational measurement losses (net of related gains) at our Mont Belvieu storage complex increased $1.6 million quarter-to-quarter. Collectively, the remainder of our consolidated operating costs and expenses increased $3.7 million quarter-to-quarter primarily due to higher operating expenses for maintenance and pipeline integrity projects during the second quarter of 2011 compared to the second quarter of 2010.

Changes in our revenues and operating costs and expenses quarter-to-quarter are explained in part by changes in energy commodity prices. For example, higher energy commodity prices result in an increase in revenues attributable to the sale of natural gas and NGLs; however, these same higher energy commodity prices also increase the associated cost of sales as purchase prices increase. The market price of natural gas (as measured at Henry Hub in Louisiana) averaged $4.32 per MMBtu during the second quarter of 2011 versus $4.09 per MMBtu during the second quarter of 2010 – a 6% quarter-to-quarter increase. The weighted-average indicative market price for NGLs was $1.50 per gallon during second quarter of 2011 versus $1.11 per gallon during the second quarter of 2010 – a 35% quarter-to-quarter increase. Our determination of the weighted-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 were $6.5 million for the second quarter of 2011 compared to $4.8 million for the second quarter of 2010. The $1.7 million quarter-to-quarter increase in general and administrative costs is primarily due to costs associated with the proposed DEP Merger and higher employee compensation expenses. Equity earnings from Evangeline increased $0.5 million quarter-to-quarter.

Operating income for the second quarter of 2011 was $29.0 million compared to $15.3 million for the second quarter of 2010. Collectively, the aforementioned changes in consolidated revenues, costs and expenses and equity earnings resulted in a $13.7 million quarter-to-quarter increase in operating income.

Interest expense decreased $0.3 million quarter-to-quarter primarily due to lower effective interest rates. Interest expense for the second quarter of 2010 included the impact of floating-to-fixed interest rate swaps, which expired in September 2010.

Consolidated net income increased $13.8 million quarter-to-quarter to $25.6 million for the second quarter of 2011 compared to $11.8 million for the second quarter of 2010. 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 $5.6 million of the DEP I Midstream Businesses' collective net income for the second quarter of 2011 compared to net income of $7.8 million for the second quarter of 2010. In connection with its ownership interests in the DEP II Midstream Businesses, EPO was attributed a net loss of $2.5 million for the second quarter of 2011 compared to a net loss of $19.3 million for the second quarter of 2010. 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 $51.2 million for the second quarter of 2011 compared to $37.1 million for the second quarter of 2010, a $14.1 million quarter-to-quarter increase. Total natural gas throughput volumes were 4.86 TBtus/d during the second quarter of 2011 compared to 4.65 TBtus/d during the second quarter of 2010. Gross operating margin from our Texas Intrastate System increased $14.4 million quarter-to-quarter primarily due to higher firm capacity reservation revenues and increased natural gas throughput volumes and fees.

NGL Pipelines & Services. Gross operating margin from this business segment was $33.0 million for the second quarter of 2011 compared to $31.6 million for the second quarter of 2010, a $1.4 million quarter-to-quarter increase. Excluding operational measurement gains recorded by Mont Belvieu Caverns, segment gross operating margin increased $3.0 million quarter-to quarter. Gross operating margin from our South Texas NGL System increased $1.9 million quarter-to-quarter primarily due to higher NGL fractionation and pipeline throughput volumes. NGL fractionation volumes increased to 84 MBPD during the second quarter of 2011 from 66 MBPD during the second quarter of 2010. NGL pipeline throughput volumes increased to 134 MBPD during the second quarter of 2011 from 112 MBPD during the second quarter of 2010. Scheduled downtime for maintenance and facility expansion projects negatively impacted NGL pipeline and fractionation volumes on our South Texas NGL System during the second quarter of 2010.

Gross operating margin from the remainder of the businesses within this segment increased $1.1 million quarter-to-quarter primarily due to increased sales margins associated with the NGL marketing activities of our Big Thicket Gathering System.

Petrochemical Services. Gross operating margin from this business segment was $3.0 million for the second quarter of 2011 compared to $2.8 million for the second quarter of 2010. Petrochemical transportation volumes decreased to 35 MBPD during the second quarter of 2011 from 37 MBPD during the second quarter of 2010. The quarter-to-quarter increase in gross operating margin is attributable to higher deficiency fee revenues on the Lou-Tex Propylene Pipeline, which were partially offset by a quarter-to-quarter increase in pipeline integrity expenses on the Lou-Tex and Sabine Propylene Pipelines.

Comparison of the Six Months Ended June 30, 2011 with the Six Months Ended June 30, 2010

Revenues for the first six months of 2011 were $586.0 million compared to $555.8 million for the first six months of 2010, a $30.2 million period-to-period increase. Consolidated revenues from sales of natural gas decreased $23.8 million period-to-period as a result of lower natural gas prices during the first six months of 2011 compared to the first six months of 2010. Revenues from sales of NGLs increased $14.8 million period-to-period attributable to both higher sales prices and volumes during the first six months of 2011 relative to the first six months of 2010. Consolidated revenues from the sale of other products increased $6.2 million period-to-period primarily due to higher sales volumes.

In the aggregate, consolidated revenues from the provision of services increased $33.0 million period-to-period. Revenues from natural gas transportation and storage services increased $22.7 million period-to-period primarily due to higher firm capacity reservation revenues and throughput volumes and fees on our Texas Intrastate System. Increased natural gas production volumes from the Eagle Ford Shale supply basin resulted in stronger demand for our natural gas transportation services during the second quarter of 2011 compared to the same period last year. Revenues from NGL and related product storage services increased $4.2 million period-to-period primarily due to higher capacity reservation revenues during the first six months of 2011 compared to the first six months of 2010, the effects of which were negatively impacted by the February 2011 NGL release and fire at the West Storage location of our Mont Belvieu storage complex. See “Significant Recent Developments” within this Item 2 for information regarding the February 2011 incident at our Mont Belvieu storage complex. Consolidated revenues from the remainder of our NGL-related services increased $6.7 million period-to-period primarily due to higher NGL fractionation and pipeline transportation volumes on our South Texas NGL System. Revenues from propylene transportation services decreased $0.6 million period-to-period primarily due to lower transportation volumes on our Lou-Tex Propylene Pipeline during the first six months of 2011 compared to the first six months of 2010.

Operating costs and expenses were $524.8 million for the first six months of 2011 compared to $512.3 million for first six months of 2010, a $12.5 million period-to-period increase. Costs related to natural gas and NGL sales decreased $6.4 million period-to-period primarily due to lower natural gas prices during the first six months of 2011 compared to the first six months of 2010. Operating costs and expenses attributable to operational measurement losses (net of related gains) at our Mont Belvieu storage complex increased $7.8 million period-to-period. Operating costs and expenses for the first six months of 2011 attributable to our Mont Belvieu storage complex also include a $5.0 million property damage deductible we expensed related to the February 2011 West Storage incident. Collectively, the remainder of our consolidated operating costs and expenses increased $6.1 million period-to-period primarily due to higher operating costs for expenses such as depreciation, maintenance and pipeline integrity projects during the first six months of 2011 compared to the first six months of 2010.

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 $4.21 per MMBtu during the first six months of 2011 versus $4.70 per MMBtu during the first six months of 2010 – a 10% period-to-period decrease. The weighted-average indicative market price for NGLs was $1.43 per gallon during the first six months of 2011 versus $1.17 per gallon during the first six months of 2010 – a 22% period-to-period increase.

General and administrative costs were $11.1 million for the first six months of 2011 compared to $9.7 million for the first six months of 2010. The $1.4 million period-to-period increase in general and administrative costs is primarily due to costs associated with the proposed DEP Merger and higher employee compensation expenses. Equity earnings from Evangeline increased $0.6 million period-to-period.

Operating income for the first six months of 2011 was $50.9 million compared to $34.0 million for the first six months of 2010. Collectively, the aforementioned changes in consolidated revenues, costs and expenses and equity earnings resulted in a $16.9 million period-to-period increase in operating income.

Interest expense decreased $0.3 million period-to-period primarily due to lower effective interest rates. Interest expense for the first six months of 2010 included the impact of floating-to-fixed interest rate swaps, which expired in September 2010

Consolidated net income increased $16.4 million period-to-period to $43.9 million for the first six months of 2011 compared to $27.5 million for the first six months of 2010. EPO was attributed $3.1 million of the net income of the DEP I Midstream Businesses for the first six months of 2011 compared to net income of $12.5 million for the first six months of 2010. EPO was attributed losses of $1.0 million and $29.5 million in connection with its ownership interests in the DEP II Midstream Businesses for the first six months of 2011 and 2010, respectively.

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 $102.9 million for the first six months of 2011 compared to $79.6 million for the first six months of 2010, a $23.3 million period-to-period increase. Total natural gas throughput volumes were 4.79 TBtus/d during the first six months of 2011 compared to 4.56 TBtus/d during the first six months of 2010. Gross operating margin from our Texas Intrastate System increased $23.6 million period-to-period primarily due to higher firm capacity reservation revenues and increased natural gas throughput volumes and fees.

NGL Pipelines & Services. Gross operating margin from this business segment was $57.3 million for the first six months of 2011 compared to $58.5 million for the first six months of 2010, a $1.2 million period-to-period decrease. Excluding operational measurement gains and losses recorded by Mont Belvieu Caverns, segment gross operating margin increased $6.6 million period-to-period. Gross operating margin from our South Texas NGL System increased $4.5 million period-to-period primarily due to higher NGL fractionation and pipeline throughput volumes. Results for the first six months of 2011 benefited from a period-to-period increase in NGL production from the Eagle Ford Shale supply basin and facility expansion projects we completed during 2010. NGL fractionation volumes increased to 86 MBPD during the first six months of 2011 from 74 MBPD during the first six months of 2010. NGL pipeline throughput volumes increased to 131 MBPD during the first six months of 2011 from 116 MBPD during the first six months of 2010.

Gross operating margin from the remainder of the businesses within this segment increased $2.1 million period-to-period primarily due to increased sales volumes and margins associated with the NGL marketing activities of our Big Thicket Gathering System.

Petrochemical Services. Gross operating margin from this business segment was $4.2 million for the first six months of 2011 compared to $5.2 million for the first six months of 2010, a $1.0 million period-to-period decrease. Petrochemical transportation volumes decreased to 30 MBPD during the first six months of 2011 from 34 MBPD during the first six months of 2010. The period-to-period decrease in gross operating margin is primarily due to lower transportation volumes on the Lou-Tex Propylene Pipeline and higher pipeline integrity expenses on the Lou-Tex and Sabine Propylene Pipelines during the first six months of 2011 compared to the first six months of 2010.

Liquidity and Capital Resources

At June 30, 2011, we had approximately $394.3 million of liquidity, which is defined as unrestricted cash on hand (adjusted for respective ownership interests in the DEP I and II Midstream Businesses) plus available credit under our Multi-Year Revolving Credit Facility. Our primary cash requirements are for routine operating expenses, debt service, working capital, capital expenditures and distributions to partners. We expect to fund our short-term cash requirements for operating expenses and sustaining capital expenditures with operating cash flows and borrowings under our Multi-Year Revolving Credit Facility. Our expenditures for long-term productive assets (e.g., business expansion projects) are expected to be funded by a variety of sources (either separately or in combination) including the use of operating cash flows, borrowings under credit facilities and cash contributions from EPO. 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 expected recurring operating and investing activities.

At June 30, 2011, our total debt principal balance outstanding was $1.15 billion, which includes $467.5 million outstanding under our Multi-Year Revolving Credit Facility due October 2013, the full amount of our $400 Million Term Loan Facility due October 2013 and $282.3 million outstanding under our Term Loan Agreement due December 2011. We expect to refinance the current maturities of our debt obligations prior to their maturity.

Over the course of 2011, we expect our liquidity level to decrease in proportion to increases in borrowings under our Multi-Year Revolving Credit Facility to fund our share of the Haynesville Extension project costs and the forecast expenditures associated with the West Storage incident (see “Significant Recent Developments” within this Item 2).

After giving effect to the limited waivers described below, we were in compliance with the financial covenants of our consolidated debt agreements at June 30, 2011.

Our revolving credit and term loan agreements include various operating and financial covenants, including provisions for maintaining a leverage ratio (i.e., a debt to Consolidated Adjusted EBITDA ratio (as such terms are defined in the underlying lending agreements)) of less than 5.00x as of the last day of any fiscal quarter. Principally as a result of increased capital spending on the Haynesville Extension project and working capital needs, our leverage ratio at June 30, 2011 was determined to be 5.04x, which (but for the waivers described below) would have exceeded the maximum leverage ratio allowed under our lending agreements. We expect that our leverage ratio as of September 30, 2011 will also exceed 5.00x. However, after the Haynesville Extension enters full commercial operations (expected in the fourth quarter of 2011), we anticipate that the ratio will be less than 5.00x as of December 31, 2011.

As a result of the foregoing, we and our lenders entered into limited waiver agreements on June 30, 2011 with respect to the quarterly leverage ratio covenant. The leverage ratio covenant is waived for the fiscal quarters ending June 30, 2011 and September 30, 2011. The limited waiver agreements will provide us with additional financial flexibility in light of our capital spending requirements for the Haynesville Extension natural gas pipeline project.

At June 30, 2011, we have two active registration statements on file with the SEC: the first covers our distribution reinvestment plan (“DRIP”), and the second covers both our employee unit purchase plan (“EUPP”) and the 2010 Plan. After taking into account limited partner units issued under our active registration statements through June 30, 2011, we may issue an additional 1,939,272 units under the DRIP, 455,459 units under the EUPP and 489,986 units under the 2010 Plan. The Merger Agreement governing our proposed merger with Enterprise contains restrictions on the issuance of additional awards under the 2010 Plan.

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 presented (dollars in millions). For information regarding the individual components of our cash flow amounts, please refer to the Unaudited Condensed Statements of Consolidated Cash Flows included under Item 1 of this quarterly report.

	For the Six Months Ended June 30,	
	2011	**2010**
Net cash flows provided by operating activities	$ 132.3	$ 106.5
Cash used in investing activities	842.9	290.9
Cash provided by financing activities	696.8	201.8

Net cash flows provided by operating activities are largely dependent on earnings from our consolidated business activities. As a result, these cash flows are exposed to certain risks. We operate predominantly in the midstream energy industry. We provide services to producers and consumers of natural gas, NGLs, refined products and certain petrochemicals. The products that we fractionate, sell or transport are principally used as fuel for residential, agricultural and commercial heating; as feedstocks 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 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 2010 Form 10-K.

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

Comparison of Six Months ended June 30, 2011 with the Six Months ended June 30, 2010

Operating activities. The $25.8 million period-to-period increase in net cash flows provided by operating activities was primarily due to the increase in gross operating margin between periods and the timing of cash receipts and disbursements.

Investing activities. The $552.0 million period-to-period increase in cash used in investing activities was primarily due to (i) a $504.3 million increase in capital expenditures primarily due to our Haynesville Extension and Eagle Ford Shale expansion projects and (ii) a $45.6 million cash receipt from EPO in January 2010 related to a loan repayment.

Financing activities. The $495.0 million period-to-period increase in cash provided by financing activities was primarily due to (i) a $281.5 million increase in net borrowings under our revolving credit facilities to fund expansion projects, (ii) a $236.2 million increase in contributions from EPO related to its funding obligations in connection with our expansion projects and (iii) a $23.4 million increase in distributions to our partners and noncontrolling interest.

Capital Spending

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

	For the Six Months Ended June 30,	
	2011	**2010**
DEP I Midstream Businesses:		
Expansion capital spending (1)	$ 550.9	$ 160.7
Sustaining capital expenditures (2)	11.8	9.2
DEP II Midstream Businesses:		
Expansion capital spending (3)	270.1	144.5
Sustaining capital expenditures (2)	15.1	28.9
Total capital spending	$ 847.9	$ 343.3

(1) EPO funded 100% of expansion capital spending through June 1, 2010. In June 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 Mont Belvieu Caverns project that consists of converting two storage caverns from NGL to refined products service, one of which was completed 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.

(3) EPO funded 100% of expansion capital spending.

The majority of our capital spending during the six months ended June 30, 2011 was attributable to the Haynesville Extension project and various Eagle Ford Shale expansion projects on our Texas Intrastate System.

Based on information currently available, we estimate our total capital spending for property, plant and equipment for the remainder of 2011 will approximate $800 million, which includes $775 million for expansion capital projects and $25 million for sustaining capital expenditures. Of these forecast amounts, Duncan Energy Partners expects to fund approximately $251 million of expansion capital project spending and $15 million of sustaining capital expenditures. EPO expects to fund the remaining expenditures.

For information regarding expansion project funding arrangements with EPO for the Haynesville Extension, see "Relationship with EPO – Amended Acadian LLC Agreement" under Note 13 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report. For information regarding expansion project funding arrangements involving the DEP II Midstream Businesses, see "Relationship 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 of this quarterly report.

At June 30, 2011, we had approximately $441.3 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 pipelines are subject to safety programs administered by the U.S. Department of Transportation ("DOT"). This federal agency has issued safety regulations containing requirements for the development of integrity management programs for hazardous liquid pipelines (e.g., 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, including those attributable to DOT regulations, for the periods presented (dollars in millions):

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2011	2010	2011	2010
Expensed	$ 3.9	$ 4.1	$ 5.2	$ 5.9
Capitalized	3.3	2.0	4.0	2.9
Total	$ 7.2	$ 6.1	$ 9.2	$ 8.8

We expect the cost of our pipeline integrity program, irrespective of whether such costs are capitalized or expensed, to approximate $22.0 million for the remainder of 2011. The cost of our pipeline integrity program was $24.6 million for the year ended December 31, 2010.

Critical Accounting Policies and Estimates

A discussion of our critical accounting policies and estimates is included in our 2010 Form 10-K. The following estimates, in our opinion, are subjective in nature, require the exercise of professional 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 the use of estimates when recording revenue and expense accruals;
§ reserves for environmental matters and litigation contingencies; and
§ natural gas imbalances.

When used in the preparation of our consolidated financial statements, such estimates are based on our current knowledge and understanding of the underlying facts and circumstances and may be revised 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 consolidated financial position, results of operations and cash flows.

Recent Accounting Developments

For information regarding recent accounting developments, see Note 2 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report.

Other Items

Contractual Obligations

Scheduled maturities of long-term debt. With the exception of routine fluctuations in the balance of the Multi-Year Revolving Credit Facility, there have been no material changes in our debt obligations since those reported in our 2010 Form 10-K. For additional information regarding our outstanding debt obligations, see Note 9 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report.

Purchase obligations. There have been no material changes in our consolidated purchase obligations since those reported in our 2010 Form 10-K, except for short-term payment obligations relating to capital projects. See "Liquidity and Capital Resources – Capital Spending" 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 insurance coverage, 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 may not fully cover every type of damage, interruption or other loss that might occur. If we were to incur a significant loss for which we were not fully insured, it could have a material impact on our financial position, results of operations and cash flows. In addition, there may be a timing difference between amounts we are required to pay in connection with a loss and amounts we receive from insurance as reimbursement. Any event that materially interrupts the revenues generated by our consolidated operations, or other losses that require us to make material 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.

During the second quarter, EPCO completed its annual insurance 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.

See "Significant Recent Developments" within this Item 2 for information regarding a February 2011 NGL release and fire at the West Storage location of our Mont Belvieu, Texas underground storage facility.

Non-GAAP Reconciliations

The following table presents a reconciliation of our measurement of total non-GAAP segment gross operating margin to GAAP operating income and further to income before provision for income taxes for the periods presented (dollars in millions):

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2011	**2010**	**2011**	**2010**
Total non-GAAP segment gross operating margin	$ 87.2	$ 71.5	$ 164.4	$ 143.3
Adjustments to reconcile total non-GAAP segment gross operating margin to GAAP net income:				
Depreciation, amortization and accretion in operating costs and expenses	(52.0)	(51.5)	(102.9)	(99.1)
Non-cash impairment charge	--	--	--	(1.5)
Gains from asset sales and related transactions in operating costs and expenses	0.3	0.1	0.5	1.0
General and administrative costs	(6.5)	(4.8)	(11.1)	(9.7)
Operating income	29.0	15.3	50.9	34.0
Interest expense	(2.9)	(3.2)	(6.0)	(6.3)
Income before provision for income taxes	$ 26.1	$ 12.1	$ 44.9	$ 27.7

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.

We define total segment gross operating margin as operating income before: (i) depreciation, amortization and accretion expense; (ii) non-cash 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 expense transactions, provision for income taxes, the cumulative effect of changes in accounting principles and extraordinary charges. Gross operating margin is presented on a 100% basis before the allocation of earnings to noncontrolling interest.

Off-Balance Sheet Arrangements

In March 2011, Evangeline made the final scheduled payment of $3.2 million on its subordinated note payable. Following this payment, Evangeline no longer has any debt obligations.

Regulatory Matters

For information regarding regulatory matters, see Note 15 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report.

Related Party Transactions

On April 28, 2011, we and our general partner entered into a definitive merger agreement with Enterprise, Enterprise GP and certain of their subsidiaries. See "Significant Recent Developments" within this Item 2 for information regarding the proposed merger with Enterprise. For additional 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 or commodity prices. Derivative instruments typically 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 quarterly report for additional information regarding our derivative instruments and hedging activities.

Our exposures to market risk have not changed materially since those reported under Item 7A, "Quantitative and Qualitative Disclosures About Market Risk," included in our 2010 Form 10-K.

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. The estimated fair value of our commodity derivative instrument portfolio and the effect of hypothetical price movements on the estimated fair value of this portfolio were nominal at both June 30, 2011 and July 19, 2011 (i.e., the remeasurement date).

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

Disclosure 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 this evaluation, as of the end of the period covered by this quarterly 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 controls over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934) during the second quarter of 2011, that have materially affected, or are reasonably likely to materially affect, our internal controls 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 litigation matters, 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 2010 Form 10-K, in addition to other information in such annual report. The risk factors set forth in our 2010 Form 10-K are 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.

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

None.

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

None.

Item 4. *(Removed and Reserved)*.

Item 5. *Other Information*.

None.

Item 6. *Exhibits.*

Exhibit Number	Exhibit*
2.1	Agreement and Plan of Merger, dated as of April 28, 2011, by and among Enterprise Products Partners L.P., Enterprise Products Holdings LLC, EPD MergerCo LLC, Duncan Energy Partners L.P. and DEP Holdings, LLC (incorporated by reference to Exhibit 2.1 to Form 8-K filed April 29, 2011).
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	First Amendment to Second Amended and Restated Limited Liability Company Agreement of Acadian Gas, LLC, dated as of March 15, 2011, by and between Enterprise Products Operating LLC and DEP Operating Partnership, L.P. (incorporated by reference to Exhibit 10.1 to Form 8-K filed March 15, 2011).

10.2	Voting Agreement, dated as of April 28, 2011, by and among Duncan Energy Partners L.P., Enterprise Products Partners L.P. and Enterprise GTM Holdings L.P. (incorporated by reference to Exhibit 10.1 to Form 8-K filed April 29, 2011).
10.3	Limited Waiver Agreement, dated as of June 30, 2011, by and among Duncan Energy Partners L.P., the Lenders party thereto and Wells Fargo Bank, National Association, as Administrative Agent under the Term Loan Agreement (incorporated by reference to Exhibit 10.1 to Form 8-K filed July 6, 2011).
10.4	Limited Waiver Agreement, dated as of June 30, 2011, by and among Duncan Energy Partners L.P., the Lenders party thereto and Wells Fargo Bank, National Association, as Administrative Agent under the Revolving Credit Agreement (incorporated by reference to Exhibit 10.2 to Form 8-K filed July 6, 2011).
31.1#	Sarbanes-Oxley Section 302 certification of W. Randall Fowler for Duncan Energy Partners L.P. for the June 30, 2011 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 June 30, 2011 Quarterly Report on Form 10-Q.
32.1#	Section 1350 certification of W. Randall Fowler for the June 30, 2011 Quarterly Report on Form 10-Q.
32.2#	Section 1350 certification of Bryan F. Bulawa for the June 30, 2011 Quarterly Report on Form 10-Q.
101.CAL#	XBRL Calculation Linkbase Document
101.DEF#	XBRL Definition Linkbase Document
101.INS#	XBRL Instance Document
101.LAB#	XBRL Labels Linkbase Document
101.PRE#	XBRL Presentation Linkbase Document
101.SCH#	XBRL Schema Document

*	With respect to exhibits incorporated by reference to Exchange Act filings, the Commission file number for Duncan Energy Partners L.P. is 1-33266.
#	Filed with this report.

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 August 9, 2011.

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 our 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: August 9, 2011

/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: August 9, 2011

/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 June 30, 2011 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: August 9, 2011

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 June 30, 2011 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: August 9, 2011