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

FORM 10-K/A
(Amendment No. 1)

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

For the fiscal year ended December 31, 2009

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)	(Zip Code)

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

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange On Which Registered
Common Units	New York Stock Exchange

Securities to be registered pursuant to Section 12(g) of the Act: None.

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

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

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 Website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).
Yes o No o

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

Large accelerated filer o 60; 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 ☑

The aggregate market value of the Duncan Energy Partners L.P.'s (or "DEP's") common units held by non-affiliates at June 30, 2009, was approximately $361.6 million, based on the closing price of such equity securities in the daily composite list for transactions on the New York Stock Exchange. This figure excludes common units beneficially owned by certain affiliates, including Dan L. Duncan and Enterprise Products Operating LLC. There were 57,676,987 common units of DEP outstanding at February 1, 2010.

EXPLANATORY NOTE

Duncan Energy Partners L.P. (the "Partnership") filed its annual report on Form 10-K for the year ended December 31, 2009 on March 1, 2010 ("Original Filing"). This Form 10-K/A is being filed to correct the classification of a related party loan amount on the Statement of Consolidated Cash Flows for the year ended December 31, 2009. Subsequent to the issuance of the Partnership's 2009 financial statements, the Partnership's management determined that a previously disclosed related party loan to EPO was incorrectly classified as an operating cash outflow rather than an investing cash outflow. As a result, cash flows provided by operating activities for the year ended December 31, 2009 were understated by $45.6 million and cas h used in investing activities for the same period was understated by an equal amount. See Note 21 of the Notes to Consolidated Financial Statements included under Item 8 of this report for additional information. In addition, related revisions were made to our discussion of liquidity and capital resources set forth on page 18. In accordance with Exchange Act Rule 12b-15, new certifications, pursuant to Section 302 and Section 906 of the Sarbanes-Oxley Act of 2002, of our Chief Executive Officer and Chief Financial Officer are also being filed. This Form 10-K/A continues to speak as of the date of the Original Filing and does not reflect additional events occurring after such date. Accordingly, this Form 10-K/A should be read in conjunction with the Original Filing and the Partnership's filings made with the Securities and Exchange Commission since March 1, 2010.

DUNCAN ENERGY PARTNERS L.P.
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SIGNIFICANT RELATIONSHIPS REFERENCED IN THIS ANNUAL 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. References to “DEP OLP” mean DEP Operating Partnership, L.P., which is a wholly owned subsidiary of Duncan Energy Partners through which Duncan Energy Partners conducts substantially all of its business.

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

References to “TEPPCO” and “TEPPCO GP” mean TEPPCO Partners, L.P. and Texas Eastern Products Pipeline Company, LLC (which is the general partner of TEPPCO), respectively, prior to their mergers with subsidiaries of Enterprise Products Partners. On October 26, 2009, Enterprise Products Partners completed the mergers with TEPPCO and TEPPCO GP. On October 27, 2009, Enterprise Products Partners’ TEPPCO and TEPPCO GP equity interests were contributed to EPO, and TEPPCO and TEPPCO GP became wholly owned subsidiaries of EPO.

References to “Enterprise GP Holdings” mean Enterprise GP Holdings L.P., a publicly traded Delaware limited partnership, the units of which are listed on the NYSE under the ticker symbol “EPE.” Enterprise GP Holdings owns EPGP. The general partner of Enterprise GP Holdings is EPE Holdings, LLC (“EPE Holdings”), a wholly owned subsidiary of Dan Duncan LLC, all of the membership interests of which are owned by Dan L. Duncan.

References to “Energy Transfer Equity” mean the business and operations of Energy Transfer Equity, L.P. and its consolidated subsidiaries, which include Energy Transfer Partners, L.P. (“ETP”). Energy Transfer Equity is a publicly traded Delaware limited partnership, the common units of which are listed on the NYSE under the ticker symbol “ETE.” The general partner of Energy Transfer Equity is LE GP, LLC (“LE GP”). ETP is a publicly traded Delaware limited partnership, the common units of which are listed on the NYSE under the ticker symbol “ETP.”

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

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

Within the context of our financial information, references to "former owners" mean EPO's ownership interests in the DEP I and DEP II Midstream Businesses prior to the effective date of the related drop down transactions.

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 "EPCO" mean Enterprise Products Company (formerly EPCO, Inc.) and its privately held affiliates. We, Enterprise Products Partners, EPO, DEP GP, EPGP, Enterprise GP Holdings and EPE Holdings are affiliates under the common control of Dan L. Duncan, the Group Co-Chairman and controlling shareholder of EPCO.

References to "Employee Partnerships" mean EPE Unit L.P. ("EPE Unit I"), EPE Unit II, L.P. ("EPE Unit II"), EPE Unit III, L.P. (EPE Unit III), Enterprise Unit L.P. ("Enterprise Unit") and EPCO Unit L.P. ("EPCO Unit"), collectively, all of which are privately held affiliates of EPCO.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

This annual report on Form 10-K/A for the year ended December 31, 2009 ("annual report") contains various forward-looking statements and information that are based on our beliefs and those of our general partner, as well as assumptions made by us and information currently available to us. When used in this document, words such as "anticipate," "project," "expect," "plan," "seek," "goal," "estimate," "forecast," "intend," "could," "should," "will," "believe," "may," "potential" and similar expressions and statements regarding our plans and objectives for future operations, are intended to identify forward-looking sta tements. Although we and our general partner believe that such 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. Such statements are subject to a variety of risks, uncertainties and assumptions as described in more detail in Item 1A of our Original Filing. 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 annual report speak only as of March 1, 2010. 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.

PART II

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

For the years ended December 31, 2009, 2008 and 2007.

The following information should be read in conjunction with our consolidated financial statements and our accompanying notes included under Item 8 within this annual report. Our discussion and analysis includes the following:

§ Cautionary Note Regarding Forward-Looking Statements.

§ Overview of Business.

§ Basis of Financial Statement Presentation.

- § Supplemental Selected Financial Information of Duncan Energy Partners L.P. – Discusses financial information and sources and uses of cash for Duncan Energy Partners L.P. on a standalone basis.

- § Significant Recent Developments – Discusses significant developments during the year ended December 31, 2009 and through March 1, 2010.

- § General Outlook for 2010.

- § Results of Operations – Discusses material year-to-year variances in our Statements of Consolidated Operations.

- § Liquidity and Capital Resources – Addresses available sources of liquidity and capital resources and includes a discussion of our capital spending program.

- § Critical Accounting Policies and Estimates.

- § Other Items – Includes information related to contractual obligations, off-balance sheet arrangements and all other matters.

Our financial statements have been prepared in accordance with U.S. generally accepted accounting principles ("GAAP").

Cautionary Note Regarding Forward-Looking Statements

This discussion contains various forward-looking statements and information that are based on our beliefs and those of our general partner, as well as assumptions made by us and information currently available to us. When used in this document, words such as "anticipate," "project," "expect," "plan," "seek," "goal," "estimate," "forecast," "intend," "could," "should," "will," "believe," "may," "potential" and similar expressions and statements regarding our plans and objectives for future operations, are intended to identify forward-looking statements. Althou gh we and our general partner believe that such 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. Such statements are subject to a variety of risks, uncertainties and assumptions as described in more detail in Item 1A of our Original Filing. 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 annual report speak only as of March 1, 2010. 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

Duncan Energy Partners is a publicly traded Delaware limited partnership, the common units of which are listed on the NYSE under the ticker symbol "DEP." Duncan Energy Partners was formed in September 2006 and did not own any assets prior to February 5, 2007, which was the date it completed its initial public offering and acquired controlling interests in the DEP I Midstream Businesses from EPO. The business purpose of Duncan Energy Partners 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. Duncan Energy Partners is engaged in the business of: (i) NGLs transportation, fractionation and marketing; (ii) storage of NGL and p etrochemical products; (iii) transportation of petrochemical products; and (iv) the gathering, transportation, marketing and storage of natural gas.

Duncan Energy Partners was owned 99.3% by its limited partners and 0.7% by its general partner, DEP GP, at December 31, 2009. EPO beneficially owned approximately 58.6% of our common units and

100% of DEP GP at December 31, 2009. DEP GP is responsible as general partner for managing our business and operations. EPCO provides all of our employees and certain administrative services to us.

Our relationship with EPO is one of our principal business advantages. Our assets connect to various midstream energy assets of EPO and form integral links within EPO's value chain of assets. We believe that the operational significance of our assets to EPO, as well as the alignment of our respective economic interests in these assets, will result in a collaborative effort between us and EPO to promote the operational efficiency of our assets and maximize their value. See Note 15 of the Notes to Consolidated Financial Statements included under Item 8 within this annual report for additional information regarding our extensive and ongoing relationships with EPO and EPCO.

DEP I Drop Down

On February 5, 2007, EPO contributed to us a 66% controlling equity interest in each of the DEP I Midstream Businesses in a drop down transaction. EPO retained the remaining 34% noncontrolling equity interest in each of these businesses. As consideration for these equity interests, we paid $459.5 million in cash and issued 5,351,571 common units to EPO. The cash portion of this consideration was financed with $198.9 million in borrowings under our Revolving Credit Facility and $260.6 million of the $290.5 million of net proceeds from our initial public offering. See Item 1 and 2 within our Original Filing for a description of the assets and operations of the DEP I Midstream Businesses.

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% general partner interest in Enterprise GC, (ii) a 51% general partner interest in Enterprise Intrastate and (iii) a 51% membership interest in Enterprise Texas. As consideration for these equity interests, we paid $280.5 million in cash and issued 37,333,887 Class B units to EPO (which automatically converted on a one-for-one basis to common units in February 2009). The cash portion of this consideration was financed with $280.0 million in borrowings under our Term Loan Agreement and $0.5 million of net proceeds from an equity offering to EPO. The market value of the Class B units at the time of issuance was approximately $449.5 million. See Item 1 and 2 within o ur Original Filing for a description of the assets and operations of the DEP II Midstream Businesses.

Noncontrolling Interests

For detailed information regarding EPO's noncontrolling interest in the DEP I and DEP II Midstream Businesses, see Note 13 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Basis of Financial Statement Presentation

See Note 1 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for information regarding the basis for presentation of our general purpose financial statements. Such information is incorporated by reference into this Item 7 discussion.

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 (the "Board") 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. Amounts presented for fiscal 2007 represent the eleven-month period from our initial public offering (effective February 1, 2007) through December 31, 2007. Amounts presented for the DEP II Midstream Businesses for fiscal 2008 represent the period from December 8, 2008 to December 31, 2008.

	Twelve Months		Eleven Months
	Ended December 31,		
	2009	2008	2007
	(dollars in millions)		
Selected income statement information:			
Equity in income - DEP I Midstream Businesses	$ 44.9	$ 37.2	$ 30.0
Equity in income - DEP II Midstream Businesses	$ 60.1	$ 4.5	$ --
General and administrative costs	$ 0.4	$ 1.4	$ 1.5
Interest expense	$ 13.5	$ 12.0	$ 9.3
Net income attributable to Duncan Energy Partners L.P.	$ 91.1	$ 28.3	$ 19.2
Selected balance sheet information at each period end:			
Investments in DEP I Midstream Businesses	$ 510.2	$ 512.7	$ 502.7
Investments in DEP II Midstream Businesses	$ 709.7	$ 730.5	$ --
Long-term debt	$ 457.3	$ 484.3	$ 200.0
Partners' equity	$ 761.4	$ 752.8	$ 314.6

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

	Twelve Months		Eleven Months
	Ended December 31,		
	2009	2008	2007
	(dollars in millions)		
Distributions paid to Duncan Energy Partners L.P. with respect to each period from:			
DEP I Midstream Businesses	$ 49.2	$ 93.7	$ 115.3
DEP II Midstream Businesses	$ 86.5	$ 5.6	$ --

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

The annualized return rate is applied to each party's aggregate investment (or "Distribution Base") in the DEP II Midstream Businesses. To the extent that we and/or EPO make capital contributions to fund expansion capital projects involving the DEP II Midstream Businesses, the Distribution Base of the contributing member will be increased by that member's capital contribution at the time such contribution is made. At December 8, 2008 and December 31, 2009, our Distribution Base was $730.0 million. EPO's Distribution Base was $452.1 million and $817.9 million at December 8, 2008 and December 31, 2009, respectively. The increase in EPO's Distribution Base is the result of its decision to fund 100% of the expansion capital projects of the DEP II Midstream Businesses since December 8, 2008. 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.

We and EPO received $86.5 million and $29.8 million, respectively, in cash distributions from the DEP II Midstream Businesses for the twelve months ended December 31, 2009. The $86.5 million (or, approximately, $21.6 million each quarter) received by us with respect to 2009 represents the annualized return rate for 2009 of 11.85% multiplied by our Distribution Base of $730.0 million. As a result, we received our expected Tier I distributions for the period. Based on EPO's Distribution Base throughout 2009, it was entitled to $83.4 million of Tier II distributions, of which it received only $29.8 million. No Tier III distributions were paid by the DEP II Midstream Businesses with respect to 2009.

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. 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 wh en we are allocated income. It is our expectation that EPO will be allocated a loss by the DEP II Midstream Businesses until such time as expansion capital projects such as the Sherman Extension and Trinity River Lateral realize their income and cash flow potential. Our participation in the expected future increase in cash flow from such projects is limited (beyond our annualized return amount) to 2% of such upside, with EPO receiving 98% of the benefit.

For information regarding the non-cash depreciation, amortization and accretion amounts of the DEP I and DEP II Midstream Businesses on a 100% basis, see Note 19 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Significant Recent Developments

The following information highlights our significant recent developments since January 1, 2009 through March 1, 2010:

Duncan Energy Partners and Enterprise Products Partners Announce Extension of Acadian Gas System into Haynesville Shale Supply Basin

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 rapidly expanding Haynesville Shale natural gas supply basin with access to additional markets through connections with the Acadian Gas System in south Louisiana and nine major interstate natural gas pipelines ("Haynesville Extension"). The Haynesville Shale producing area is believed to cover approximately 2 million acres in northwest Louisiana, almost all of which is under lease. Production from the approximately 200 wells drilled to date is estimated at more than 1 Bcf/d. Over 400 locations are in various stages of drilling and completion wit h approximately 150 rigs now working in the region.

As currently designed, the Haynesville Extension will have the potential capacity to transport up to 2.1 Bcf/d of natural gas from the Haynesville area through a 249-mile pipeline that will connect with our existing Acadian Gas System. The pipeline is expected to be in service during the third quarter of 2011.

The Acadian Gas System serves major natural gas markets along the Mississippi River corridor between Baton Rouge and New Orleans and has the ability to make physical deliveries into the Henry Hub. The Haynesville Extension will also have interconnects with major interstate pipelines including Florida

Gas, Texas Eastern, Transco, Sonat, Columbia Gulf, Trunkline, ANR, Tennessee Gas and Texas Gas. Together with the capacity of the existing Acadian Gas System, the extension project will provide approximately 6.2 Bcf/d of redelivery capacity into an estimated 12 Bcf/d of available downstream pipeline takeaway capacity. Initially, the project will connect to nine Haynesville Shale producer locations in DeSoto and Red River parishes.

Along with providing much needed natural gas takeaway capacity for growing Haynesville production, the new pipeline is expected to provide shippers the opportunity to benefit from additional pricing points and diverse service options and access to the south Louisiana marketplace. For producers, the more flexible contracting options associated with an intrastate pipeline environment is expected to help facilitate a seamless transaction for the producer from the field to the end user.

Currently, we own a 66% equity interest in the entities that own the Acadian Gas System, with EPO owning the remaining 34% equity interest. We are in discussions with EPO regarding the funding and related aspects of the Haynesville Extension project.

Service Begins on Sherman Extension Pipeline

In late February 2009, we and EPO announced that construction had been completed on the 173-mile Sherman Extension expansion of our Texas Intrastate System, which extends through the heart of the prolific Barnett Shale natural gas production basin of north Texas. The completion of the Sherman Extension adds 1.2 Bcf/d of incremental natural gas takeaway capacity from the region, while providing producers in the Barnett Shale, and as far away as the Waha area of west Texas, with greater flexibility to reach the most attractive natural gas markets. The Texas Intrastate System is part of our Natural Gas Pipelines & Services business segment through interconnections with pipelines that serve the Midwest and Northeast regions of the United States.

Initially, the Sherman Extension began providing intrastate service, and its subsequent NGPA 311 transportation was in very limited service due to pipeline integrity issues on the connecting third-party take-away pipeline, the Gulf Crossing Pipeline owned by Boardwalk Pipeline Partners, LP. The Gulf Crossing Pipeline began ramping up its operations on August 1, 2009. As a result, the Sherman Extension started billing its demand charges at 95% of its contracted volumes, which are 950 MMcf/d. Effective September 1, 2009, the Sherman Extension started billing demand charges on 100% of contracted volumes, irrespective of actual transportation volumes. We are currently flowing approximately 700 MMcf/d. The demand charges are approximatel y $5.0 million a month.

Registration Statements and Equity Offerings

In connection with our June 2009 equity offering, we issued 8,943,400 common units and generated net proceeds of approximately $137.4 million after underwriting discounts and other offering expenses. The net proceeds were used to repurchase an equal number of our common units beneficially owned by EPO. The repurchased common units were subsequently cancelled.

In December 2009, we filed a registration statement with the Securities Exchange Commission (“SEC”) authorizing the issuance of up to 2,000,000 common units in connection with a distribution reinvestment plan (“DRIP”). Plan participants may purchase our common units at a discount ranging from 0% to 5% (currently set at 5%), which will be set from time to time by us.

In February 2010, we filed a registration statement with the SEC authorizing the issuance of up to 1,000,000 common units in connection with an employee unit purchase plan and a long-term incentive plan that became effective on February 11, 2010. See Item 9B of our Original Filing for additional information regarding the approval of these plans.

General Outlook for 2010

Commercial Outlook

We provide midstream energy services to producers and consumers of natural gas, NGLs and certain petrochemicals. Factors that can affect the demand for our services include global and U.S. economic conditions, the demand for energy, the market price of energy, the cost to develop natural gas and crude oil reserves in the U.S. and the cost and availability of capital to energy companies to invest in drilling activities.

The global economic contraction that began in late 2007 appeared to show signs of stabilizing in the second half of 2009 with most of the twenty largest developed economies ("G20") reporting quarter- over-quarter growth in real gross domestic product ("GDP") beginning in the third quarter of 2009. However, approximately 65 percent of the G20 were still reporting year-over-year contraction in real GDP in 2009. The United States reported quarter-over-quarter real GDP growth of 2.2 percent and 5.7 percent for the third and fourth quarters of 2009, respectively, after five quarters of contraction in real GDP since the beginning of 2008. Real GDP growth for 2009 compared to 2008 was 0.1 percent.

Impacted by general economic conditions and price shock-induced conservation by consumers, U.S. demand for petroleum products and natural gas (as reported by the U.S. Energy Information Administration) for the first ten months of 2009 decreased approximately 5.4 percent and 2.1 percent, respectively, from the same periods in 2008 and by approximately 11 percent and 1.5 percent, respectively, from the first ten months of 2007. Likewise, U.S. demand for petroleum products for transportation purposes (e.g. motor gasoline, distillate, jet fuel) for the first ten months of 2009 declined by 2.7 percent and 6.3 percent compared to the first ten months of 2008 and 2007, respectively. The rate of decline in U.S. demand for petroleum products since mid-2009 appears to be moderating and demand for natural gas since mid-2009 has increased by 1.5 percent compared to the same period in 2008.

Energy prices have generally rebounded with the recovery in demand, economic growth and stability in the capital markets. The average prices for West Texas Intermediate crude oil and Mont Belvieu ethane for December 2009 increased by approximately 82 percent and 120 percent, respectively, from December 2008; while natural gas at the Henry Hub in December 2009 decreased by 8 percent from December 2008. Notably, there has been a substantial change in the price relationship between natural gas and crude oil. In December 2008, natural gas was priced at 81 percent of crude oil on an energy equivalent basis compared to 41 percent in December 2009. We believe changes in the price relationships of crude oil and crude oil derivatives to natural gas and NGLs in the past year could lead to a long-term structural change in feedstock selection by the petrochemical industry.

During 2009 and the beginning of 2010, natural gas and NGLs have a significant price advantage over more costly crude oil and crude oil derivatives (such as naphtha). This has been primarily driven by (i) a decline in global crude oil production; (ii) more government-held acreage being off limits to non-sovereign energy companies; (iii) geopolitical risk; (iv) growing demand for crude oil by China and other developing countries; (v) the globalization of natural gas prices with more LNG facilities becoming operational; and (vi) the technological breakthroughs around the development of natural gas shale resource basins that have decreased finding and development costs.

For ethylene producers, the largest consumers of NGLs, this has meant that ethane and propane were their most consistently profitable feedstocks in 2009 and are forecasted to be so in 2010. This feedstock cost advantage and a weak U.S. dollar provided U.S. ethylene producers with a competitive advantage globally, especially relative to naphtha crackers in Europe and Asia. Per industry publications, approximately 24% of 2009 aggregate domestic production of high density polyethylene ("HDPE"), low density polyethylene ("LDPE") and PVC were for the export market.

U.S. ethylene producers responded by maximizing the use of NGLs as a feedstock, rationalizing some of their facilities and investing capital to modify their furnaces to crack more NGLs. The U.S. ethylene industry consumed almost 1.3 MMBbls/d of NGL feedstocks in December 2009, an 81 percent increase over 700 MBPD of NGLs consumed in December 2008. We estimate domestic crackers are in the process of adding approximately 100 MBPD of new capacity to crack ethane and propane through modifications to their existing facilities. Certain international ethylene crackers have reacted to the NGL feedstock cost advantage by importing propane to displace crude oil derivatives to feed their heavy crackers, including propane produced in the U.S.

Export ethylene derivative demand remains strong in early 2010, but is expected to moderate as Middle East production increases later this year. Chemical margins in the U.S. are also forecasted to compress due to increased competition, but overall demand for domestically produced ethylene is expected to decline only by approximately 1.5% to 48.3 billion lbs/year in 2010 and then increase 2.3% to 49.4 billion lbs/year in 2011. With the global recession abating, domestic demand is expected to increase, consuming the production that was sold into the export markets in 2008 and 2009.

Strong end user demand for NGLs and increases in NGL-rich natural gas production are expected to (i) keep our NGL fractionators, pipelines and storage facilities operating at high utilization rates and (ii) provide us with opportunities to invest capital to build new natural gas gathering and NGL pipeline facilities.

Natural gas prices have significantly declined from a peak of over $13.00 per MMBtu in mid-2008 to $5.35 per MMBtu in December 2009. This price decrease coupled with the residual impact of a higher cost of capital for certain energy companies has generally resulted in energy companies reducing their drilling capital expenditure budgets. This has led to a substantial decrease in the number of rigs drilling for natural gas in the U.S., declining from a peak of 1,606 rigs in August 2008 to a low of 665 rigs in July 2009 as natural gas prices approached a low of $1.88 per MMBtu in September 2009. The natural gas rig count has since rebounded to 878 rigs at the beginning of February 2010. Even though the total natural gas rig count has dropped by almost half, the substantial efficiencies of horiz ontal drilling in the non-conventional and shale resource basins have allowed producers to maintain overall natural gas deliverability. As a result, rig count is not necessarily a reliable indicator of the level of future natural gas production. The rig count has increased in the developing Haynesville Shale, Marcellus Shale and Eagle Ford Shale areas where producers are drilling to hold recently executed leases. Generally, rig counts remain significantly below peak levels in areas with conventional natural gas reserves and areas where producers have leases held by production.

In Texas, the rig count at the end of 2009 was 50 percent below peak levels during 2008. Since the end of 2009, the rig count in Texas has increased 13 percent. The rig count in the Barnett Shale area at the end of 2009 was approximately 55 percent below peak levels. While the Barnett Shale has a significant amount of undeveloped natural gas reserves at relatively low finding costs, much of the acreage under lease is held by production. Certain energy companies that were active in the Barnett Shale have elected to reallocate a portion of their capital resources in the near term to drill wells in the Haynesville Shale in northwest Louisiana, the Marcellus Shale in Pennsylvania and West Virginia, and the Eagle Ford Shale in south Texas to secure recently acquired leases that are not held by production. Despite the lower rig count in the Barnett Shale and certain other areas of Texas, we expect transportation volumes on our Texas Intrastate System to increase by up to 10 percent in 2010 with volume growth principally attributable to a full year of operations for the Sherman Extension pipeline and the commencement of operations on the Trinity River Lateral pipeline during the third quarter of 2010. Both of these pipelines serve the Barnett Shale region.

South Texas has seen an increase in drilling activity attributable to the development of the Eagle Ford Shale, which runs parallel to the Texas Gulf Coast and adjacent to our Texas Intrastate System. We have completed several small pipeline projects that enable us to gather and transport up to 300 MMcf/d of new natural gas production from the Eagle Ford Shale. Generally, energy companies have had early success in the Eagle Ford Shale and several have indicated they plan to accelerate their drilling programs. Production associated with this region includes crude oil, NGL-rich natural gas and lean natural gas. We believe there may be opportunities for us to invest capital to incrementally expand our natural gas pipeline and storage facilities and NGL pipeline and fractionation facilities to fa cilitate production growth from this region.

The rig count in Louisiana has increased 14 percent since the end of 2008 primarily due to development activities in the Haynesville Shale area of northwest Louisiana. Based on industry success, natural gas production from this region is expected to grow rapidly over the next several years. In the fourth quarter of 2009, we announced that seven energy companies had executed long-term agreements to support the Haynesville Extension expansion of our Acadian Gas System. The Haynesville Extension is a 249-mile, 42-inch pipeline designed to transport up to 2.1 Bcf/d. Construction of the pipeline will begin in 2010 and is scheduled to be completed by the end of the third quarter of 2011.

Liquidity Outlook

The debt and equity capital markets have significantly improved since the beginning of 2009. The cost of our term debt and equity capital has generally declined to pre-financial crisis levels. The availability of term debt and equity capital has also improved. The availability of credit commitments from most banks has also improved from a year ago; however, the cost of new bank debt is significantly higher than pre-crisis levels (by approximately 2 percent on borrowed money) and the term of bank capital is generally limited to no more than three years.

Our $300 million Revolving Credit Facility and $282.3 million Term Loan Agreement mature in February and December of 2011, respectively. While we currently believe our credit cost under new bank facilities could increase by approximately 2.0 to 2.5 percent on borrowed money, we believe we will have sufficient liquidity and access to capital markets to refinance these facilities. Based on amounts outstanding under these facilities at December 31, 2009, on an annual basis, we estimate the increase in our credit costs under similar bank facilities currently available in the market could range from approximately $9.0 million to $11.5 million.

In 2007, we executed derivative instruments with an aggregate notional amount of $175 million to reduce our exposure to changes in the 1-month London Interbank Offered Rate ("LIBOR") (which is a part of the cost of our bank credit facility). Under these derivative instruments, our counterparties pay us the 1-month LIBO rate in effect on the periodic reset date and we pay our counterparties an average fixed rate of 4.62 percent. In 2009, our aggregate net payments to counterparties under these derivative instruments and corresponding increase in interest expense was approximately $6.5 million. These derivative instruments expire in September 2010. In the near term, the expiration of these derivative instruments should reduce our future interest expense; however, upon termination, 100 percent of our debt will be subject to changes in the 1-month LIBO rate.

The U.S. government is expected to run substantial annual budget deficits, exceeding a trillion dollars that will require a corresponding issuance of debt by the U.S. treasury from 2010 through 2013. The interest rate on U.S. Treasury debt has an impact on the cost of our debt. At this time, we are uncertain what the impact of the large issuance of U.S. Treasury debt and the prevailing economic and capital market conditions will have on the cost and availability of capital.

We expect our proactive approach to funding capital spending and other partnership needs, combined with sufficient trade credit to operate our businesses efficiently, and available borrowing capacity under our credit facilities, to provide us with a foundation to meet our anticipated liquidity and capital requirements in 2010. We also believe that we will be able to access the capital markets in 2010 to maintain financial flexibility.

Results of Operations

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

We evaluate segment performance based on the non-GAAP financial measure of gross operating margin. Gross operating margin (either in total or by individual segment) is an important performance measure of the core profitability of our operations. This measure forms the basis of our internal financial reporting and is used by management in deciding how to allocate capital resources among business segments. We believe that investors benefit from having access to the same financial measures that management uses in evaluating segment results. The GAAP financial measure most directly comparable to total segment gross operating margin is operating income.

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

We include equity earnings from Evangeline in our measurement of segment gross operating margin and operating income. Our equity investment in Evangeline is a vital component of our business strategy and important to the operations of Acadian Gas. This method of operation enables us to achieve favorable economies of scale relative to the level of investment and business risk assumed versus what we could accomplish on a stand-alone basis. Evangeline's operations complement those of Acadian Gas. As circumstances dictate, we may increase our ownership interest in Evangeline or make other equity method investments.

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), which we report on a net basis to our ownership interest.

	For the Year Ended December 31,		
	2009	**2008**	**2007**
Natural Gas Pipelines & Services, net:			
Natural gas throughput volumes (BBtus/d)			
Texas Intrastate System	3,902	4,021	3,550
Acadian Gas System:			
Transportation volumes	436	378	416
Sales volumes (1)	320	331	308
Total natural gas throughput volumes	4,658	4,730	4,274
NGL Pipelines & Services, net:			
NGL throughput volumes (MBPD)			
South Texas NGL System - Pipelines	109	126	124
NGL fractionation volumes (MBPD)			
South Texas NGL System - Fractionators	77	80	72
Petrochemical Services, net:			
Propylene throughput volumes (MBPD)			
Lou-Tex Propylene Pipeline	21	25	25
Sabine Propylene Pipeline	9	10	12
Total propylene throughput volumes	30	35	37

(1) Includes average net sales volumes for Evangeline of 50 BBtus/d for each of the years ended December 31, 2009, 2008 and 2007, respectively.

Comparison of Results of Operations

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

	For the Year Ended December 31,		
	2009	2008	2007
Revenues	$ 979.3	$ 1,598.1	$ 1,220.3
Operating costs and expenses	908.3	1,512.8	1,171.0
General and administrative costs	11.2	18.3	13.1
Equity in income of Evangeline	1.1	0.9	0.2
Operating income	60.9	67.9	36.4
Interest expense	14.0	12.0	9.3
Net income	45.8	55.3	23.6
Net loss (income) attributable to noncontrolling interest:			
DEP I Midstream Businesses – Parent	(15.3)	(11.4)	(20.0)
DEP II Midstream Businesses – Parent	60.6	4.0	--
Net income attributable to Duncan Energy Partners	91.1	47.9	3.6

For information regarding our noncontrolling interest amounts, see Note 13 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

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

	For the Year Ended December 31,		
	2009	2008	2007
Natural Gas Pipelines & Services	$ 148.2	$ 159.0	$ 122.5
NGL Pipelines & Services	103.4	82.9	87.9
Petrochemical Services	10.5	11.1	14.3
Total segment gross operating margin	$ 262.1	$ 253.0	$ 224.7

For a reconciliation of non-GAAP gross operating margin to GAAP operating income and further to GAAP net income, see "Other Items – Non-GAAP Reconciliations" within this Item 7. For additional information regarding our business segments, see Note 13 of the Notes to Consolidated Financial Statements included under Item 8 within this annual report.

The following table summarizes the contribution to revenues from each business segment (including the effects of eliminations and adjustments) during the periods indicated (dollars in millions):

	For the Year Ended December 31,		
	2009	2008	2007
Natural Gas Pipelines & Services:			
Sales of natural gas	$ 460.2	$ 1,100.2	$ 794.1
Natural gas transportation services	263.2	246.7	212.8
Natural gas storage services	15.3	8.4	1.5
Total segment revenues	$ 738.7	$ 1,355.3	$ 1,008.4
NGL Pipelines & Services:			
Sales of NGLs	$ 35.0	$ 47.9	$ 40.3
Sales of other products	11.3	15.0	10.8
NGL and petrochemical storage services	104.9	87.4	68.9
NGL fractionation services	29.5	32.4	30.3
NGL transportation services	43.8	43.6	42.5
Other services	2.5	2.3	1.7
Total segment revenues	$ 227.0	$ 228.6	$ 194.5
Petrochemical Services:			
Propylene transportation services	$ 13.6	$ 14.2	$ 17.4
Total consolidated revenues	$ 979.3	$ 1,598.1	$ 1,220.3

Comparison of Year Ended December 31, 2009 with Year Ended December 31, 2008

Revenues for 2009 were $979.3 million compared to $1.60 billion for 2008. The $618.8 million year-to-year decrease in our revenues is primarily due to lower energy commodity sales volumes and prices during 2009 relative to 2008. These factors accounted for a $656.6 million year-to-year decrease in revenues from the sale of natural gas and NGLs. Revenues from natural gas transportation and storage services increased $23.4 million year-to-year primarily due to firm capacity reservation fees earned by our Sherman Extension pipeline during 2009. The Sherman Extension pipeline began earning capacity reservation fees during August 2009.

Revenues from NGL fractionation, transportation, storage and other services increased $15.0 million year-to-year primarily due to increased NGL storage activity and higher storage fees. Revenues from propylene transportation decreased $0.6 million year-to-year due to lower transportation volumes in 2009 relative to 2008.

Operating costs and expenses were $908.3 million for 2009 versus $1.51 billion for 2008. The $604.5 million year-to-year decrease in our operating costs and expenses is primarily due to a decrease in the cost of sales associated with our natural gas and NGL marketing activities. The cost of sales of our natural gas and NGL products decreased $644.2 million year-to-year as a result of lower sales volumes and energy commodity prices. Costs and expenses related to natural gas transportation and storage services increased $24.1 million year-to-year. Operating costs and expenses were lower during 2008 when we recorded favorable adjustments for certain audit claims and changes in anticipated costs to complete an environmental remediation projec t. In addition, operating expenses increased during 2009 due to higher employee compensation and maintenance expenses and operating expenses for the Sherman Extension pipeline.

Costs and expenses of our NGL fractionation, transportation, storage and other services decreased $7.6 million year-to-year primarily due to lower operational measurement losses at Mont Belvieu Caverns' storage complex and lower fuel and maintenance expenses. Collectively, the remainder of our consolidated operating costs and expenses increased $23.2 million year-to-year as a result of higher depreciation expense due to our recent completion of the Sherman Extension pipeline and $4.2 million of non-cash impairment charges recorded in 2009.

Changes in our revenues and operating costs and expenses year-to-year are explained in part by changes in energy commodity prices. In general, lower energy commodity prices result in a decrease in our revenues attributable to the sale of natural gas and NGLs; however, these lower commodity prices also decrease the associated cost of sales as purchase prices fall. The market price of natural gas (as measured at Henry Hub in Louisiana) averaged $3.99 per MMBtu during 2009 versus $9.04 per MMBtu during 2008 – a 56% year-to-year decrease. The weighted-average indicative market price for NGLs was $0.85 per gallon during 2009 versus $1.40 per gallon during 2008 – a 39% year-to-year decrease. Our determination of the weighted-average indic ative 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 $11.2 million for 2009 compared to $18.3 million for 2008. The $7.1 million year-to-year decrease in general and administrative costs is primarily due to lower costs associated with the DEP II Midstream Businesses. Equity earnings from Evangeline increased $0.2 million year-to-year.

Operating income for 2009 was $60.9 million compared to $67.9 million for 2008. Consolidated revenues and certain operating costs and expenses can fluctuate significantly due to changes in energy commodity prices without necessarily affecting our operating income to the same degree. Consequently, the aforementioned changes in revenues, costs and expenses and equity earnings contributed to the $7.0 million year-to-year decrease in operating income.

Interest expense increased $2.0 million year-to-year primarily due to borrowings we made in connection with the DEP II drop down transaction in December 2008. See Note 11 of the Notes to

Consolidated Financial Statements included under Item 8 of this annual report for information regarding borrowings we made during December 2008. Provision for income taxes increased $0.2 million year-to-year primarily due to the Texas Margin Tax.

As a result of items noted in the previous paragraphs, net income decreased $9.5 million year-to-year to $45.8 million for 2009 compared to $55.3 million for 2008.

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 total net income to arrive at the amount of net income attributable to Duncan Energy Partners L.P. EPO was attributed $15.3 million of the net income of the DEP I Midstream Businesses during 2009 compared to $11.4 million during 2008. The year-to-year variance in EPO's share of the net income of the DEP I Midstream Businesses is primarily due to improved earnings from these businesses. See Note 13 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for information regarding our determination of net income attribut able to EPO's noncontrolling interest.

EPO was attributed $60.6 million of losses in connection with its ownership interests in the DEP II Midstream Businesses during 2009 compared to $4.0 million of losses for the period from December 8, 2008 to December 31, 2008. In the aggregate, the DEP II Midstream Businesses distributed $116.3 million of cash and posted net losses of $0.5 million during 2009. As a result of its priority return rights in the DEP II Midstream Businesses, Duncan Energy Partners received its full cash distributions of $86.5 million and was attributed income of $60.1 million from these businesses for 2009. EPO is attributed a loss to the extent that aggregate net income for the DEP II Midstream Businesses is less than the income attributed by these businesses to Duncan Energy Partners. EPO received $29.8 million in cash distributions from the DEP II Midstream Businesses in 2009.

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

Natural Gas Pipelines & Services. Gross operating margin from this business segment was $148.2 million for 2009 compared to $159.0 million for 2008, a $10.8 million year-to-year decrease. Total natural gas throughput volumes were 4,658 BBtus/d for 2009 compared to 4,730 BBtus/d for 2008. Gross operating margin from our natural gas pipelines includes $24.8 million of firm capacity reservation fees earned by our Sherman Extension pipeline during 2009. Contributions to gross operating margin from our Sherman Extension pipeline were more than offset by a year-to-year increase in operating expenses on our Texas Intrastate System, lower revenues from the sale of pipeline condensate and lower natural gas sales volumes and margins on the Acadian Gas System.

Gross operating margin from our Wilson natural gas storage facility increased $5.4 million year-to-year primarily due to higher firm storage reservation fees earned during 2009 compared to 2008.

NGL Pipelines & Services. Gross operating margin from this business segment was $103.4 million for 2009 compared to $82.9 million for 2008, a $20.5 million year-to-year increase. Gross operating margin from Mont Belvieu Caverns' storage complex increased $22.9 million year-to-year. Mont Belvieu Caverns recorded operational measurement losses of $1.7 million for 2009 compared to operational measurement losses of $6.8 million for 2008. Net of operational measurement losses, gross operating margin from Mont Belvieu Caverns' storage complex increased $17.8 million year-to-year as a result of higher revenues due to increased storage reservation and excess throughput fees and higher storage vo lumes. Collectively, gross operating margin from the remainder of the businesses classified within this segment decreased $2.4 million year-to-year primarily due to lower NGL sales margins and lower NGL transportation and fractionation volumes.

Petrochemical Services. Gross operating margin from this business segment was $10.5 million for 2009 compared to $11.1 million for 2008. Petrochemical transportation volumes decreased to 30 MBPD during 2009 from 35 MBPD during 2008. The $0.6 million year-to-year decrease in segment gross operating margin is primarily due to lower transportation volumes on our Lou-Tex Propylene Pipeline.

Comparison of Year Ended December 31, 2008 with Year Ended December 31, 2007

Revenues for 2008 were $1.60 billion compared to $1.22 billion for 2007. The $377.8 million year-to-year increase in our revenues is primarily due to higher energy commodity sales volumes and prices during 2008 relative to 2007. These factors accounted for a $317.9 million year-to-year increase in revenues from the sale of natural gas and NGLs. Revenues from our natural gas transportation and storage businesses increased $40.8 million year-to-year primarily due to higher pipeline transportation fees and volumes during 2008 relative to 2007. Revenues from NGL fractionation, transportation, storage and other services increased $22.3 million year-to-year primarily due to increased NGL storage activity and higher storage fees. Revenues from propylene transportation decreased $3.2 mill ion year-to-year due to lower transportation fees and volumes in 2008 relative to 2007.

Operating costs and expenses were $1.51 billion for 2008 versus $1.17 billion for 2007. The $341.8 million year-to-year increase in our operating costs and expenses is primarily due to an increase in the cost of sales associated with our natural gas and NGL marketing activities. The cost of sales of our natural gas and NGL products increased $308.1 million year-to-year as a result of an increase in volumes and energy commodity prices. Costs and expenses from our natural gas transportation and storage businesses increased $15.9 million year-to-year primarily due to higher repair and maintenance expenses. Costs and expenses from NGL fractionation, transportation, storage and other services increased $26.1 million year-to-year primarily due to hig her operating costs and expenses from Mont Belvieu Caverns' storage complex. Collectively, the remainder of our consolidated operating costs and expenses decreased $8.3 million year-to-year primarily due to lower depreciation expense for 2008 compared to 2007.

In the first quarter of 2008, we reviewed the assumptions underlying the estimated remaining economic lives of our assets. As a result of our review, we increased the remaining useful lives of certain assets as of January 1, 2008, most notably the assets that constitute our Texas Intrastate System. These revisions extended the remaining useful life of such assets to incorporate recent data showing that proved natural gas reserves supporting volumes for these assets had increased their estimated useful life. There were no changes to the residual values of these assets. These revisions prospectively reduced our depreciation expense on assets having carrying values totaling $2.72 billion at January 1, 2008. As a result of this change in estimate, depreciation expense decreased by approximately $20.0 million for the year ended December 31, 2008. The reduction in depreciation expense increased operating income and net income by equal amounts from what they would have been absent the change. Overall, depreciation, amortization and accretion expense included in operating costs and expenses was $167.3 million and $175.3 million for the years ended December 31, 2008 and 2007, respectively. The reduction in depreciation expense in 2008 resulting from the change in estimate was partially offset by depreciation expense on newly constructed assets that were placed in service during 2008, primarily additions to our Texas Intrastate System and Mont Belvieu storage complex.

Changes in our revenues and operating costs and expenses year-to-year are explained in part by changes in energy commodity prices. The Henry Hub market price of natural gas averaged $9.04 per MMBtu during 2008 versus $6.86 per MMBtu during 2007. The weighted-average indicative market price for NGLs was $1.40 per gallon during 2008 versus $1.19 per gallon during 2007.

General and administrative costs were $18.3 million for 2008 compared to $13.1 million for 2007. The $5.2 million year-to-year increase in general and administrative costs is primarily due to higher employee-related costs and professional services. Equity earnings from Evangeline increased $0.7 million year-to-year.

Operating income for 2008 was $67.9 million compared to $36.4 million for 2007. Collectively, the aforementioned changes in revenues, costs and expenses and equity earnings contributed to the $31.5 million year-to-year increase in operating income.

Interest expense increased $2.7 million year-to-year primarily due to borrowings we made in connection with the DEP II drop down transaction in December 2008 and a decrease in the amount of interest capitalized during 2008 relative to 2007. Provision for income taxes decreased $3.1 million year-to-year primarily due to lower accruals for the Texas Margin Tax during 2008 compared to 2007.

As a result of items noted in the previous paragraphs, net income increased $31.7 million year-to-year to $55.3 million for 2008 compared to $23.6 million for 2007.

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 total net income to arrive at the amount of net income attributable to Duncan Energy Partners L.P. EPO was attributed $11.4 million of the net income of the DEP I Midstream Businesses during 2008 compared to $20.0 million during 2007. The year-to-year variance in EPO's share of the net income of the DEP I Midstream Businesses is primarily due to the special allocations of operational measurement gains and losses and depreciation expense to EPO. EPO was attributed $4.0 million of losses in connection with its ownership interests in the DEP II Midstream Businesses for the period from December 8, 2008 to December 31, 2008.

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

Natural Gas Pipelines & Services. Gross operating margin from this business segment was $159.0 million for 2008 compared to $122.5 million for 2007, a $36.5 million year-to-year increase. Total natural gas throughput volumes were 4,730 BBtus/d for 2008 compared to 4,274 BBtus/d for 2007. Gross operating margin from our Texas Intrastate System increased $23.6 million year-to-year attributable to: (i) a 471 BBtus/d year-to-year increase in natural gas throughput volumes; (ii) increased transportation and capacity reservation fees; and (iii) higher NGL condensate sales revenues. Gross operating margin from our Acadian Gas System increased $6.4 million year-to- year largely due to improved natural gas sales margins during 2008 relative to 2007. Collectively, results for the Texas Intrastate and Acadian Gas Systems include $1.2 million of property damage repair expenses during 2008 resulting from Hurricanes Gustav and Ike. Equity earnings from our investment in Evangeline increased $0.7 million year-to-year primarily due to higher volumes, lower pipeline integrity expenses and lower interest expense during 2008 relative to 2007.

Gross operating margin from our Wilson natural gas storage facility increased $5.8 million year-to-year. Results from this facility were negatively impacted during 2007 due to expenses related to mechanical issues and ongoing repairs. Storage volumes increased during 2008 as we completed repairs and began returning the storage caverns to commercial service.

NGL Pipelines & Services. Gross operating margin from this business segment was $82.9 million for 2008 compared to $87.9 million for 2007, a $5.0 million year-to-year decrease. Gross operating margin from Mont Belvieu Caverns' storage complex decreased $2.7 million year-to-year.

Mont Belvieu Caverns recorded operational measurement losses of $6.8 million for 2008 compared to operational measurement gains of $4.5 million for 2007. Net of operational measurement gains and losses, gross operating margin from Mont Belvieu Caverns' storage complex increased $8.6 million year-to-year as a result of higher revenues due to increased storage reservation and excess throughput fees and higher storage volumes. Collectively, gross operating margin from the remainder of the businesses classified within this segment decreased $2.3 million year-to-year primarily due to higher expenses for repair and maintenance and pipeline integrity on our South Texas NGL System. Segment operating costs and expenses for 2008 include $0.4 million of property damage repair expenses resulting from Hu rricane Ike.

Petrochemical Services. Gross operating margin from this business segment was $11.1 million for 2008 compared to $14.3 million for 2007. Petrochemical transportation volumes decreased to 35 MBPD during 2008 from 37 MBPD during 2007. The $3.2 million year-to-year decrease in segment gross operating margin is primarily due to lower transportation volumes and fees on our Lou-Tex Propylene Pipeline.

Liquidity and Capital Resources

Management's Discussion and Analysis has been revised for the effect of the restatement, as reflected in Note 21 of the Notes to Consolidated Financial Statements under Item 8 of this annual report.

Our primary cash requirements, in addition to normal operating expenses and debt service, are for working capital, capital expenditures, business combinations and distributions to our partners. We expect to fund our short-term needs for such items as operating expenses and sustaining capital expenditures with operating cash flows and borrowings under our Revolving Credit Facility. Capital expenditures for long-term needs resulting from business expansion projects and acquisitions are expected to be funded by a variety of sources (either separately or in combination) including operating cash flows, borrowings under credit facilities, cash contributions from our Parent, the issuance of additional equity and debt securities and proceeds from divestitures of ownership interests in assets to affiliates or third partie s. 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.

At December 31, 2009, we had approximately $121 million of liquidity, which includes availability under our Revolving Credit Facility. At December 31, 2009, our total debt balance was $457.3 million, which includes $175.0 million outstanding under our Revolving Credit Facility and the $282.3 million we borrowed on December 8, 2008 under our Term Loan Agreement. We were in compliance with the covenants of our loan agreements at December 31, 2009 and 2008.

It is our belief that we will continue to have adequate liquidity and capital resources to fund future recurring operating and investing activities for the next twelve months. For a discussion of our liquidity outlook, see "General Outlook for 2010" within this Item 7.

Registration Statements

We may issue equity or debt securities to assist us in meeting our liquidity and capital spending requirements. We have a universal shelf registration statement on file with the SEC that allows us to issue up to $1 billion in debt and equity securities for general partnership purposes. After taking into account a June 2009 equity offering made under this registration statement (see table below), we can issue approximately $856.4 million of additional securities under this registration statement in the future.

Underwritten Equity Offering	**Number of Common Units Issued**	**Offering Price** (1)	**Net Proceeds** (2) (in millions)
June 2009 underwritten offering (3)	8,943,400	$ 16.00	$ 137.4

(1) The public offering price, net of the underwriting discount, was $15.36 per unit.
(2) Net proceeds from these equity offerings were used to repurchase an equal number of our common units beneficially owned by EPO.
(3) Includes our underwriters' exercise of a portion of their 30-day option to purchase additional common units.

We also have a registration statement on file with the SEC authorizing the issuance of up to 2,000,000 common units in connection with the DRIP. The DRIP gives unitholders of record and beneficial owners of our common units the ability to increase the number of our common units they own through voluntarily reinvesting their quarterly cash distributions into the purchase of additional common units. Plan participants may purchase our common units at a discount ranging from 0% to 5% (currently set at 5%), which will be set from time to time by us. We did not issue any common units under the DRIP during the year ended December 31, 2009. In February 2010, we issued 10,385 common units in connection with the DRIP.

In February 2010, we filed a registration statement with the SEC authorizing the issuance of up to 1,000,000 common units in connection with an employee unit purchase plan and a long-term incentive plan. These plans became effective on February 11, 2010. See Item 9B of our Original Filing for additional information.

Cash Flows from Operating, Investing and Financing Activities

The following table summarizes our cash flows from operating, investing and financing activities for the periods indicated (dollars in millions). For information regarding the individual components of our cash flow amounts, see the Statements of Consolidated Cash Flows included under Item 8 within this annual report.

	For the Year Ended December 31,		
	2009	2008	2007
Net cash flows provided by operating activities	$ 201.6	$ 220.1	$ 217.1
Cash used in investing activities	428.8	748.8	352.4
Cash provided by financing activities	218.1	539.5	137.5

We use the indirect method to compute net cash flows provided by operating activities. Net cash flows provided by operating activities are largely dependent on earnings from our business activities. As a result, these cash flows are exposed to certain risks. We operate predominantly in the midstream energy industry. We provide services for producers and consumers of natural gas, NGLs and 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 decli ne in general economic conditions, reduced demand for the end products made with our products, or increased competition from other service providers or producers due to pricing differences or other reasons, could have a negative impact on our earnings and operating cash flows.

Cash used in investing activities primarily represents expenditures for additions to property, plant and equipment. Cash provided by financing activities generally consists of borrowings and repayments of debt, distributions to and contributions from owners, and proceeds from the issuance of equity securities.

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

Comparison of 2009 with 2008

Operating activities. Net cash flows provided by operating activities were $201.6 million for the year ended December 31, 2009 compared to $220.1 million for the year ended December 31, 2008. The change in operating cash flow is primarily due to the timing of related cash receipts and disbursements offset by a $9.1 million increase in gross operating margin for the year ended December 31, 2009 in comparison to the year ended December 31, 2008.

Investing activities. Cash flows used in investing activities were $428.8 million for the year ended December 31, 2009 compared to $748.8 million for the year ended December 31, 2008. The $320.0 million year-to-year decrease is primarily due to the completion of growth capital projects on the DEP II Midstream Businesses that were under construction in 2008. In February 2009, we completed the construction of the Sherman Extension Pipeline, which is a component of our Texas Intrastate System. The Sherman Extension Pipeline began operations on August 1, 2009.

Financing activities. Cash flows provided by financing activities were $218.1 million for the year ended December 31, 2009 compared to $539.5 million for the year ended December 31, 2008. The $321.4 million year-to-year decrease is due to: (i) a $222.9 million decrease in net contributions, primarily related to growth capital projects, from EPO as both a former owner (pre-drop down) and as noncontrolling interest; (ii) a $311.2 million decrease in net borrowings under our loan agreements; (iii) a $54.5 million increase in distributions to our unitholders and general partners; (iv) a $14.0 million increase in distributions to EPO; and (v) a $280.5 decrease in distributions to EPO related to the DEP II drop down in 2008.

Comparison of 2008 with 2007

Operating activities. Net cash flows provided by operating activities were $220.1 million for the year ended December 31, 2008 compared to $217.1 million for the year ended December 31, 2007. The improvement in operating cash flow is generally due to the increase in gross operating margin between periods (see "Results of Operations" included within this Item 7) adjusted for the timing of related cash receipts and disbursements.

Investing activities. Net cash flows used in investing activities were $748.8 million for the year ended December 31, 2008 compared to $352.4 million for the year ended December 31, 2007. The increase of $396.4 million is primarily due to growth capital spending for additions to property, plant and equipment of the DEP II Midstream Businesses (e.g., the Sherman Extension Pipeline).

Financing activities. Net cash flows provided by financing activities were $539.5 million for the year ended December 31, 2008 compared to $137.5 million for the year ended December 31, 2007. The increase of $402.0 million is primarily due to: (i) a $378.8 million year-to-year increase in contributions by the former owners of the DEP II Midstream Businesses primarily due to the funding of growth capital spending of these businesses; (ii) a $78.3 million year-to-year increase in contributions from EPO primarily due to growth capital spending of the DEP I Midstream Businesses; (iii) a year-to-year increase of $84.2 million in net borrowings under loan agreements, which consisted primarily of $282.3 received from the execution of our Term Loan Agreement; (iv) a $290.0 million year-to-year decrease in net proceeds from equity offerings; and (v) a $179.0 million year-to-year decrease in distributions to EPO related to the DEP I and DEP II drop down transactions.

Capital Expenditures

Part of our business strategy involves expansion through business combinations and growth capital projects. The following table summarizes our capital spending by activity on a cash basis for the periods indicated (dollars in millions):

	For the Twelve Months Ended December 31, 2009	2008
DEP I Midstream Businesses:		
Expansion capital spending (1)	$ 28.5	$ 127.7
Sustaining capital expenditures (2)	13.9	12.8
DEP II Midstream Businesses:		
Expansion capital spending (1)	311.0	576.5
Sustaining capital expenditures (2)	35.7	42.5
Total capital spending	$ 389.1	$ 759.5

(1) EPO funded 100% of expansion capital spending during the periods presented.
(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.

The majority of our capital spending during 2009 and 2008 was attributable to ongoing expansions of the Texas Intrastate System, including the Sherman Extension and Trinity River Lateral projects.

Based on information currently available, we estimate our consolidated capital spending for property, plant and equipment for 2010 will approximate $840 million, which includes estimated expenditures of approximately $780 million for growth capital projects and approximately $60 million for sustaining capital expenditures.

Our forecast of capital expenditures is based on current announced growth plans. With respect to growth capital spending, EPO (as Parent) funds the majority of such project costs under agreements executed in connection with the DEP I and DEP II drop down transactions. In order to fund its share of growth capital spending, Duncan Energy Partners depends on its ability to generate the required funds from either operating cash flows or from other means, including borrowings under debt agreements and the issuance of equity. See Note 13 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for information regarding EPO's funding of certain growth capital spending of South Texas NGL and Mont Belvieu Caverns. For information regarding the expansion capi tal funding arrangements of the DEP II Midstream Businesses, see "Significant Relationships and Agreements with EPO - Company and Limited Partnership Agreements - DEP II Midstream Businesses" under Note 15 of the Notes to Consolidated Financial Statements included under Item 8 within this annual report.

At December 31, 2009, we had approximately $175.3 million in purchase commitments outstanding that relate to our capital spending for property, plant and equipment. These commitments primarily relate to expansion projects on our Texas Intrastate System and Acadian Gas System.

Pipeline Integrity Costs

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

In April 2002, a subsidiary of EPO acquired several midstream energy assets, which included the Texas Intrastate System from El Paso Corporation ("El Paso"). With respect to these assets, El Paso agreed to indemnify our subsidiary for any pipeline integrity costs it incurred (whether paid or payable) for five years following the acquisition date. The indemnity provisions did not take effect until such costs exceeded $3.3 million annually; however, the amount reimbursable by El Paso was capped at $50.2 million in the aggregate. In 2007, the DEP II Midstream Businesses recovered $31.1 million from El Paso related to the 2006 pipeline integrity expenditures. During 2007, the DEP II Midstream Businesses also received the final payment of $5.4 million from El Paso related to this inde mnity.

The following table summarizes our pipeline integrity costs, net of indemnity payments received from El Paso, for the periods indicated (dollars in millions):

	For the Year Ended December 31,		
	2009	**2008**	**2007**
Expensed	$ 14.1	$ 20.6	$ 14.9
Capitalized	17.0	22.9	24.1
Total	$ 31.1	$ 43.5	$ 39.0

We expect our cash outlay for the pipeline integrity program, irrespective of whether such costs are capitalized or expensed, to approximate $42.5 million for 2010.

Critical Accounting Policies and Estimates

In our financial reporting process, we employ methods, estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities as of the date of our financial statements. These methods, estimates and assumptions also affect the reported amounts of revenues and expenses during the reporting period. Investors should be aware that actual results could differ from these estimates if the underlying assumptions prove to be incorrect. The following describes the estimation risk currently underlying our most significant financial statement items.

Depreciation Methods and Estimated Useful Lives of Property, Plant and Equipment

In general, depreciation is the systematic and rational allocation of an asset's cost, less its residual value (if any), to the periods it benefits. The majority of our property, plant and equipment is depreciated using the straight-line method, which results in depreciation expense being incurred evenly over the life of the assets. Our estimate of depreciation incorporates assumptions regarding the useful economic lives and residual values of our assets. At the time we place our assets into service, we believe such assumptions are reasonable; however, circumstances may develop that would cause us to change these assumptions, which would change our depreciation amounts prospectively. Examples of such circumstances include:

§ changes in laws and regulations that limit the estimated economic life of an asset;

§ changes in technology that render an asset obsolete;

§ changes in expected salvage values; or

§ changes in the forecast life of applicable resource basins, if any.

At December 31, 2009 and 2008, the net book value of our property, plant and equipment was $4.55 billion and $4.33 billion, respectively. We recorded $176.7 million, $158.5 million and $163.4 million in depreciation expense for the years ended December 31, 2009, 2008 and 2007, respectively.

For additional information regarding our property, plant and equipment, including changes made in the first quarter of 2008 in the estimated remaining useful lives of certain of our assets, see Notes 2 and 8 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Measuring Recoverability of Long-Lived Assets and Equity Method Investments

In general, long-lived assets (including intangible assets with finite useful lives and property, plant and equipment) are reviewed for impairment whenever events or changes in circumstances indicate that their carrying amount may not be recoverable. Examples of such events or changes might be production declines that are not replaced by new discoveries or long-term decreases in the demand or price of natural gas, crude oil or NGLs. Long-lived assets with recorded values that are not expected to be recovered through forecast future cash flows are written-down to their estimated fair values. The carrying value of a long-lived asset is not recoverable if it exceeds the sum of undiscounted estimated cash flows expected to result from the use and eventual disposition of the asset. Our estimates of such undiscounted cash flows are based on a number of assumptions including anticipated operating margins and volumes; estimated useful life of the asset or asset group; and estimated salvage values. An impairment charge would be recorded for the excess of a long-lived asset's carrying value over its estimated fair value, which is based on a series of assumptions similar to those used to derive undiscounted cash flows. Those assumptions also include usage of probabilities for a range of possible outcomes, market values and replacement cost estimates.

An equity method investment is evaluated for impairment whenever events or changes in circumstances indicate that there is a possible loss in value of the investment other than a temporary decline. Examples of such events include sustained operating losses of the investee or long-term negative changes in the investee's industry. The carrying value of an equity method investment is not recoverable if it exceeds the sum of the discounted estimated cash flows expected to be derived from the investment. This estimate of discounted cash flows is based on a number of assumptions including discount rates; probabilities assigned to different cash flow scenarios; anticipated margins and volumes and estimated useful life of the investment. A significant change in these underlying assumptions cou ld result in our recording an impairment charge.

During 2009, we recognized $4.2 million of asset impairment charges, which are reflected as a component of operating costs and expenses. No such asset impairment charges were recorded in 2008 or 2007. We did not recognize any impairment charges related to our equity method investment in Evangeline during the three years ended December 31, 2009.

For additional information regarding impairment charges associated with our long-lived assets, see Note 6 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Amortization Methods and Estimated Useful Lives of Qualifying Intangible Assets

The specific, identifiable intangible assets of a business enterprise depend largely upon the nature of its operations. Potential intangible assets include, intellectual property, such as technology, patents, trademarks, trade names, customer contracts and relationships and non-compete agreements, as well as other intangible assets. The method used to value each intangible asset will vary depending upon a number of factors, including the nature of the asset and the economic returns it is generating or is expected to generate.

Our customer relationship intangible assets primarily represent the customer bases we acquired in connection with the DEP II drop down. These customer relationships were acquired by Enterprise Products Partners in connection with a merger transaction it completed in 2004 and a business combination it completed in 2007. We amortize the value of our customer relationships to earnings using methods that closely resemble the pattern in which the economic benefits of the underlying NGL and natural gas resource bases from which the customers produce are estimated to be consumed or otherwise used. Our estimate of the useful life of each resource base is predicated on a number of factors, including reserve estimates and the economic viability of production and ex ploration activities.

We acquired contract-based intangible assets in connection with the DEP I and DEP II drop down transactions. Our contract-based intangible assets represent the rights we own arising from discrete contractual agreements. A contract-based intangible asset with a finite life is amortized over its estimated useful life (or term), which is the period over which the asset is expected to contribute directly or indirectly to the cash flows of an entity. Our estimates of useful life are based on a number of factors, including:

§ the expected useful life of the related tangible assets (e.g., fractionation facility, pipeline or other asset);

§ any legal or regulatory developments that would impact such contractual rights; and

§ any contractual provisions that enable us to renew or extend such agreements.

If our underlying assumptions regarding the estimated useful life of an intangible asset change, then the amortization period for such asset would be adjusted accordingly. Changes in the estimated useful life of an intangible asset would impact operating costs and expenses prospectively from the date of change. If we determine that an intangible asset’s unamortized cost is not recoverable due to impairment; we would be required to reduce the asset’s carrying value to fair value. Any such write-down of the value of an intangible asset would increase operating costs and expenses at that time.

At December 31, 2009 and 2008, the carrying value of our intangible asset portfolio was $43.8 million and $52.3 million, respectively. We recorded $8.5 million, $9.1 million and $7.2 million in amortization expense associated with our intangible assets for the years ended December 31, 2009, 2008 and 2007, respectively.

For additional information regarding our intangible assets, see Notes 2 and 10 of the Notes to Consolidated Financial Statements included under Item 8 within this annual report.

Methods We Employ to Measure the Fair Value of Goodwill

Goodwill represents the excess of the purchase prices we paid for certain businesses over their respective fair values. We do not amortize goodwill; however, we test our goodwill for impairment at the beginning of each fiscal year, and more frequently, if circumstances indicate it is more likely than not that the fair value of goodwill is below its carrying amount. Our goodwill testing involves the determination of a reporting unit's fair value, which is predicated on our assumptions regarding the future economic prospects of the reporting unit.

Such assumptions include:

- § discrete financial forecasts for the assets classified within the reporting unit, which rely on management's estimates of operating margins and transportation volumes;

- § long-term growth rates for cash flows beyond the discrete forecast period; and

- § appropriate discount rates.

If the fair value of the reporting unit (including its inherent goodwill) is less than its carrying value, a charge to earnings is required to reduce the carrying value of the goodwill to its implied fair value. The carrying value of our goodwill was $4.9 million at both December 31, 2009 and 2008. Our goodwill represents an allocation to the DEP II Midstream Businesses of the goodwill recorded by Enterprise Products Partners in connection with a merger transaction it completed in 2004. We did not record any goodwill impairment charges during the three years ended December 31, 2009.

For additional information regarding our goodwill, see Notes 2 and 10 of the Notes to Consolidated Financial Statements included under Item 8 within this annual report.

Our Revenue Recognition Policies and Use of Estimates for Revenues and Expenses

In general, we recognize revenue from customers when all of the following criteria are met:

- § persuasive evidence of an exchange arrangement exists;

- § delivery has occurred or services have been rendered;

- § the buyer's price is fixed or determinable; and

- § collectibility is reasonably assured.

We record revenue when sales contracts are settled (i.e., either physical delivery of product has taken place or the services designated in the contract have been performed). For additional information regarding our revenue recognition policies, see Note 4 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report. We record any necessary allowance for doubtful accounts as required by our established policy.

Our use of estimates for certain revenues and expenses has increased as a result of SEC regulations that require us to submit financial information on accelerated time frames. Such estimates are necessary due to the time required to compile actual billing information and receive third-party data needed to record transactions for financial reporting purposes. Changes in facts and circumstances may result in revised estimates and could affect our reported financial statements and accompanying disclosures. If the assumptions underlying our estimates prove to be substantially incorrect, it could result in material adjustments in results of operations between periods. We review our estimates based on currently available information.

Reserves for Environmental Matters

Our business activities are subject to various federal, state and local laws and regulations governing environmental quality and pollution control. Such laws and regulations may, in certain instances, require us to remediate current or former operating sites where specified substances have been released or disposed of. We accrue reserves for environmental matters when our assessments indicate that it is probable that a liability has been incurred and an amount can be reasonably estimated. Our assessments are based on studies, as well as site surveys, to determine the extent of any environmental damage and the necessary requirements to remediate this damage. Future environmental developments, such as increasingly strict environmental laws and additional claims for damages to property, employees and other persons resulting from current or past operations, could result in substantial additional costs beyond our current reserves. In accruing for environmental remediation liabilities, costs of future expenditures for environmental remediation are not discounted to their present value, unless the amount and timing of the expenditures are fixed or reliably determinable. At December 31, 2009, none of our estimated environmental remediation liabilities were discounted to present value since the ultimate amount and timing of cash payments for such liabilities were not readily determinable.

At December 31, 2009 and 2008, we had a liability for environmental remediation of $0.5 million and $0.6 million, respectively, which was derived from a range of reasonable estimates based upon studies and site surveys. We have recorded our best estimate of the cost of remediation activities. See Notes 2 and 17 of the Notes to Consolidated Financial Statements included under Item 8 within this annual report for additional information regarding environmental matters.

Natural Gas Imbalances

In the natural gas pipeline transportation business, imbalances frequently result from differences in natural gas volumes received from and delivered to our customers. Such differences occur when a customer delivers more or less gas into our pipelines than is physically redelivered back to them during a particular time period. The vast majority of our settlements are through in-kind arrangements whereby incremental volumes are delivered to a customer (in the case of an imbalance payable) or received from a customer (in the case of an imbalance receivable). Such in-kind deliveries are ongoing and take place over several months. In some cases, settlements of imbalances accumulated over a period of time are ultimately cashed out and are generally negotiated at values w hich approximate average market prices over a period of time. As a result, for gas imbalances that are ultimately settled over future periods, we estimate the value of such current assets and liabilities using average market prices, which we believe is representative of the value of the imbalances upon final settlement. Changes in natural gas prices may impact our estimates.

The following table presents our natural gas imbalance receivables/payables at the dates indicated:

	December 31,	
	2009	**2008**
Natural gas imbalance receivables	$ 9.8	$ 35.7
Natural gas imbalance payables (1)	11.0	43.6

(1) Reflected as a component of “Accrued product payables” on our Consolidated Balance Sheets included in Item 8 of this annual report.

Other Items

Insurance Matters

We participate as a named insured in EPCO’s insurance program, which provides us with property damage, business interruption and other coverages, the scope and amounts of which are customary and sufficient for the nature and extent of our operations. In light of recent hurricane and other weather-related events, the renewal of policies for weather-related risks resulted in significant increases in premiums and certain deductibles, as well as changes in the scope of coverage. For additional information regarding insurance matters, see Note 18 of the Notes Consolidated Financial Statements included under Item 8 of this annual report.

Contractual Obligations

The following table summarizes our significant contractual obligations at December 31, 2009 (dollars in millions). For additional information regarding these obligations, see Note 17 of the Notes to Consolidated Financial Statements included under Item 8 within this annual report.

	Payment or Settlement due by Period				
Contractual Obligations (1)	**Total**	**Less than 1 year**	**1-3 years**	**4-5 years**	**More than 5 years**
Scheduled maturities of long term debt (2)	$ 457.3	$ --	$ 457.3	$ --	$ --
Estimated cash interest payments (3)	$ 14.8	$ 11.1	$ 3.7	$ --	$ --
Operating lease obligations (4)	$ 115.6	$ 9.0	$ 17.6	$ 14.0	$ 75.0
Purchase obligations:					
Product purchase commitments:					
Estimated payment obligations:					
Natural gas (5)	$ 511.7	$ 257.3	$ 254.4	$ --	$ --
Other	$ 0.1	$ *	$ 0.1	$ --	$ --
Underlying major volume commitments:					
Natural gas (in BBtus)	77,207	40,657	36,550	--	--
Capital expenditure commitments (6)	$ 175.3	$ 175.3	$ --	$ --	$ --
Other long-term liabilities (7)	$ 6.4	$ --	$ 0.2	$ --	$ 6.2
Total	$ 1,281.2	$ 452.7	$ 733.3	$ 14.0	$ 81.2

* Indicates amounts are immaterial and less than $0.1 million.

(1) The contractual obligations presented in this table reflect 100% of our subsidiaries' obligations even though we own less than a 100% equity interest in our operating subsidiaries.

(2) Represents our scheduled future maturities of consolidated debt principal obligations for the periods indicated. See Note 11 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for information regarding our debt obligations.

(3) Our estimated cash payments for interest are based on the principle amount of consolidated debt obligations outstanding at December 31, 2009. In calculating these amounts, we applied the weighted-average variable interest rates paid during 2009 associated with such debt. See Note 11 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for the weighted-average variable interest rates charged in 2009 under our credit agreements. In addition, our estimate of cash payments for interest gives effect to interest rate swap agreements that were in place at December 31, 2009. See Note 6 of the Notes to Consolidated Financial Statements included unde r Item 8 of this annual report for information regarding these derivative instruments.

(4) Primarily represents operating leases for (i) underground caverns for the storage of natural gas and NGLs and (ii) land held pursuant to right-of-way agreements. See Note 17 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for information regarding our operating leases.

(5) Represents natural gas purchase commitments of Acadian Gas to satisfy its sales commitments to Evangeline. See Note 17 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for information regarding our purchase obligations. The estimated payment obligations are based on contractual prices in effect at December 31, 2009 applied to all future volume commitments. Actual future payment obligations may vary depending on prices at the time of delivery.

(6) Represents short-term unconditional payment obligations related to our capital projects (on a 100% basis). With respect to the amount presented, we expect reimbursements of $113.9 million from EPO.

(7) As reflected on our Consolidated Balance Sheet at December 31, 2009, other long-term liabilities primarily represent noncurrent portions of asset retirement obligations. For information regarding our asset retirement obligations, see Note 7 of our Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Off-Balance Sheet Arrangements

At December 31, 2009, Evangeline's debt obligations consisted of (i) $3.2 million in principal amount of 9.90% fixed rate Series B senior secured notes due December 2010 and (ii) a $7.5 million subordinated note payable, due in 2011. Evangeline expects to fund the repayment of its debt obligations (including accrued interest) using operating cash flows.

We have no other off-balance sheet arrangements, as described in Item 303(a)(4)(ii) of Regulation S-K, that have had or are reasonably expected to have a material current or future effect on our financial position, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources.

Related Party Transactions

For information regarding our related party transactions, see Note 15 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report as well as Item 13 of our Original Filing.

Non-GAAP Reconciliations

The following table presents a reconciliation of our non-GAAP measure of total segment gross operating margin to GAAP operating income and net income for the periods indicated (dollars in millions):

	For the Year Ended December 31,		
	2009	**2008**	**2007**
Total segment gross operating margin	$ 262.1	$ 253.0	$ 224.7
Adjustments to reconcile total segment gross operating margin to operating income:			
Depreciation, amortization and accretion in operating costs and expenses	(186.3)	(167.3)	(175.3)
Impairment charge included in operating costs and expenses	(4.2)	--	--
Gain on asset sales and related transactions in operating costs and expenses	0.5	0.5	0.1
General and administrative costs	(11.2)	(18.3)	(13.1)
GAAP operating income	60.9	67.9	36.4
Other income (expense), net	(13.8)	(11.5)	(8.6)
Provision for income taxes	(1.3)	(1.1)	(4.2)
GAAP net income	$ 45.8	$ 55.3	$ 23.6

Recent Accounting Developments

The accounting standard setting bodies have recently issued accounting guidance that will or may affect our future financial statements:

§ Fair Value Measurements; and

§ Consolidation of Variable Interest Entities

For additional information regarding these recent accounting developments, see Note 3 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Item 8. ***Financial Statements and Supplementary Data.***

Our consolidated financial statements, together with the independent registered public accounting firm's report of Deloitte & Touche LLP ("Deloitte & Touche") begin on page F-1 of this annual report.

PART IV

Item 15. ***Exhibits and Financial Statement Schedules.***

(a) The following documents are filed as a part of this annual report:

(1) Financial Statements: See Index to Consolidated Financial Statements on page F-1 of this annual report for financial statements filed as part of this annual report.

(2) Financial Statement Schedules: All schedules have been omitted because they are either not applicable, not required or the information called for therein appears in the consolidated financial statements or notes thereto.

(3) Exhibits.

Exhibit Number	Exhibit*
3.1	Certificate of Limited Partnership of Duncan Energy Partners L.P. (incorporated by reference to Exhibit 3.1 to Form S-1 Registration Statement (Reg. No. 333-138371) filed November 2, 2006).
3.2	Amended and Restated Agreement of Limited Partnership of Duncan Energy Partners L.P., dated February 5, 2007 (incorporated by reference to Exhibit 3.1 to Form 8-K filed February 5, 2007).
3.3	Amendment No. 1 to the Amended and Restated Agreement of Limited Partnership of Duncan Energy Partners L.P. dated December 27, 2007 (incorporated by reference to Exhibit 3.1 to Form 8-K/A filed January 3, 2008).
3.4	Amendment No. 2 to the Amended and Restated Agreement of Limited Partnership of Duncan Energy Partners L.P. dated November 6, 2008 (incorporated by reference to Exhibit 3.4 to Form 10-Q filed November 10, 2008).
3.5	Third Amendment to the Amended and Restated Agreement of Limited Partnership of Duncan Energy Partners L.P., dated December 8, 2008 (incorporated by reference to Exhibit 3.1 to Form 8-K filed December 8, 2008).
3.6	Fourth Amendment to the Amended and Restated Agreement of Limited Partnership of Duncan Energy Partners L.P. dated June 15, 2009 (incorporated by reference to Exhibit 3.1 to Form 8-K filed June 15, 2009).
3.7	Certificate of Formation of DEP Holdings, LLC (incorporated by reference to Exhibit 3.3 to Form S-1 Registration Statement (Reg. No. 333-138371) filed November 2, 2006).
3.8	Second Amended and Restated Limited Liability Company Agreement of DEP Holdings, LLC, dated May 3, 2007 (incorporated by reference to Exhibit 3.4 to Form 10-Q filed May 4, 2007).
3.9	First Amendment to the Second Amended and Restated Limited Liability Company Agreement of DEP Holdings, LLC dated November 6, 2008 (incorporated by reference to Exhibit 3.8 to Form 10-Q filed November 10, 2008).
3.10	Certificate of Formation of DEP OLPGP, LLC (incorporated by reference to Exhibit 3.5 to Form S-1 Registration Statement (Reg. No. 333-138371) filed November 2, 2006).
3.11	Amended and Restated Limited Liability Company Agreement of DEP OLPGP, LLC, dated January 19, 2007 (incorporated by reference to Exhibit 3.6 to Amendment No. 3 to Form S-1 Registration Statement (Reg. No. 333-138371) filed January 22, 2007).
3.12	Certificate of Limited Partnership of DEP Operating Partnership, L.P. (incorporated by reference to Exhibit 3.7 to Form S-1 Registration Statement (Reg. No. 333-138371) filed November 2, 2006).
3.13	Agreement of Limited Partnership of DEP Operating Partnership, L.P., dated September 29, 2006 (incorporated by reference to Exhibit 3.8 to Amendment No. 1 to Form S-1 Registration Statement (Reg. No. 333-138371) filed December 15, 2006).
10.1***	Amended and Restated 2008 Enterprise Products Long-Term Incentive Plan (February 23, 2010) (incorporated by reference to Exhibit 10.7 to Form 8-K filed by Enterprise Products Partners L.P. on February 26, 2010).
10.2***	Form of Option Grant Award under the Amended and Restated 2008 Enterprise Products

	Long-Term Incentive Plan for awards issued before February 23, 2010 (incorporated by reference to Exhibit 4.3 to Form S-8 filed by Enterprise Products Partners L.P. on May 6, 2008).
10.3***	Amendment to Form of Option Grant Award under the Amended and Restated 2008 Enterprise Products Long-Term Incentive Plan for awards issued before February 23, 2010 (incorporated by reference to Exhibit 10.8 to Form 8-K filed by Enterprise Products Partners L.P. on February 26, 2010).
10.4***	Form of Option Grant Award under the Amended and Restated 2008 Enterprise Products Long-Term Incentive Plan (incorporated by reference to Exhibit 10.9 to Form 8-K filed by Enterprise Products Partners L.P. on February 26, 2010).
10.5***	Form of Employee Restricted Unit Grant Award under the Amended and Restated 2008 Enterprise Products Long-Term Incentive Plan (incorporated by reference to Exhibit 10.10 to Form 8-K filed by Enterprise Products Partners L.P. on February 26, 2010).
10.6***	Form of Non-Employee Director Restricted Unit Grant Award under the Amended and Restated 2008 Enterprise Products Long-Term Incentive Plan (incorporated by reference to Exhibit 10.11 to Form 8-K filed by Enterprise Products Partners L.P. on February 26, 2010).
10.7***	Enterprise Products 1998 Long-Term Incentive Plan (Amended and Restated as of February 23, 2010) (incorporated by reference to Exhibit10.1 to Form 8-K filed by Enterprise Products Partners L.P. on February 26, 2010).
10.8***	Form of Option Grant Award under the Enterprise Products 1998 Long-Term Incentive Plan for awards issued before May 7, 2008 (incorporated by reference to Exhibit 10.2 to Form 10-Q filed by Enterprise Products Partners L.P. on November 8, 2007).
10.9***	Form of Option Grant Award under the Enterprise Products 1998 Long-Term Incentive Plan for awards issued on or after May 7, 2008 but before February 23, 2010 (incorporated by reference to Exhibit 10.4 to Form 10-Q filed by Enterprise Products Partners L.P. on May 12, 2008).
10.10***	Amendment to Form of Option Grant Award under the Enterprise Products 1998 Long-Term Incentive Plan for awards issued before February 23, 2010 (incorporated by reference to Exhibit 10.2 to Form 8-K filed by Enterprise Products Partners L.P. on February 26, 2010).
10.11***	Form of Option Grant Award under the Enterprise Products 1998 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.3 to Form 8-K filed by Enterprise Products Partners L.P. on February 26, 2010).
10.12***	Form of Restricted Unit Grant Award under the Enterprise Products 1998 Long-Term Incentive Plan for awards issued before February 23, 2010 (incorporated by reference to Exhibit 10.3 to Form 10-Q filed by Enterprise Products Partners L.P. on November 8, 2007).
10.13***	Amendment to Form of Restricted Unit Grant Award under the Enterprise Products 1998 Long-Term Incentive Plan for awards issued before February 23, 2010 (incorporated by reference to Exhibit 10.4 to Form 8-K filed by Enterprise Products Partners L.P. on February 26, 2010).
10.14***	Form of Employee Restricted Unit Grant Award under the Enterprise Products 1998 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.5 to Form 8-K filed by Enterprise Products Partners L.P. on February 26, 2010).
10.15***	Form of Non-Employee Director Restricted Unit Grant Award under the Enterprise Products 1998 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.6 to Form 8-K filed by Enterprise Products Partners L.P. on February 26, 2010).
10.16***	Enterprise Products Company 2005 EPE Long-Term Incentive Plan (amended and restated as of February 23, 2010) (incorporated by reference to Exhibit 10.1 to Form 8-K filed by Enterprise GP Holdings L.P. on February 26, 2010).
10.17***	Form of Unit Appreciation Right Grant Award (DEP Holding, LLC Directors) under the Enterprise Products Company 2005 EPE Long-Term Incentive Plan (incorporated by reference to Exhibit 10.24 to Form 10-K filed April 2, 2007).
10.18***	Form of Employee Restricted Unit Grant Award under the Enterprise Products Company 2005 EPE Long-Term Incentive Plan (incorporated by reference to Exhibit 10.3 to Form 8-K filed by Enterprise GP Holdings L.P. on February 26, 2010).
10.19***	Form of Non-Employee Director Restricted Unit Grant Award under the Enterprise Products Company 2005 EPE Long-Term Incentive Plan (incorporated by reference to Exhibit 10.4 to

	Form 8-K filed by Enterprise GP Holdings L.P. on February 26, 2010).
10.20***	Form of Phantom Unit Grant Award under the Enterprise Products Company 2005 EPE Long-Term Incentive Plan (incorporated by reference to Exhibit10.5 to Form 8-K filed by Enterprise GP Holdings L.P. on February 26, 2010).
10.21***	2010 Duncan Energy Partners L.P. Long-Term Incentive Plan (Amended and Restated as of February 23, 2010) (incorporated by reference to Exhibit 10.1 to Form 8-K filed February 26, 2010).
10.22***	Form of Option Award under the 2010 Duncan Energy Partners L.P. Long-Term Incentive Plan (incorporated by reference to Exhibit 10.2 to Form 8-K filed February 26, 2010).
10.23***	Form of Employee Restricted Unit Grant Award under the 2010 Duncan Energy Partners L.P. Long-Term Incentive Plan (incorporated by reference to Exhibit 10.3 to Form 8-K filed February 26, 2010).
10.24***	Form of Non-Employee Director Restricted Unit Grant Award under the 2010 Duncan Energy Partners L.P. Long-Term Incentive Plan (incorporated by reference to Exhibit 10.4 to Form 8-K filed February 26, 2010).
10.25***	Agreement of Limited Partnership of Enterprise Unit L.P. dated February 20, 2008 (incorporated by reference to Exhibit 10.1 to Form 8-K filed by Enterprise Products Partners L.P. on February 26, 2008).
10.26***	First Amendment to Agreement of Limited Partnership of Enterprise Unit L.P. dated December 2, 2009 (incorporated by reference to Exhibit 10.4 to Form 8-K filed by Enterprise GP Holdings L.P. on December 8, 2009).
10.27***	Agreement of Limited Partnership of EPCO Unit L.P. dated November 13, 2008 (incorporated by reference to Exhibit 10.5 to Form 8-K filed by Enteprise Products Partners L.P. on November 18, 2008).
10.28***	First Amendment to Agreement of Limited Partnership of EPCO Unit L.P. dated December 2, 2009 (incorporated by reference to Exhibit 10.5 to Form 8-K filed by Enterprise GP Holdings L.P. on December 8, 2009).
10.29***	Agreement of Limited Partnership of EPE Unit L.P. dated August 23, 2005 (incorporated by reference to Exhibit 10.2 to Form 8-K filed by Enterprise GP Holdings L.P. on September 1, 2005).
10.30***	First Amendment to Agreement of Limited Partnership of EPE Unit L.P. dated August 7, 2007 (incorporated by reference to Exhibit 10.3 to Form 10-Q filed August 8, 2007).
10.31***	Second Amendment to Agreement of Limited Partnership of EPE Unit L.P. dated July 1, 2008 (incorporated by reference to Exhibit 10.1 to Form 8-K filed by Enterprise GP Holdings L.P. on July 7, 2008).
10.32***	Third Amendment to Agreement of Limited Partnership of EPE Unit L.P. dated December 2, 2009 (incorporated by reference to Exhibit 10.1 to Form 8-K filed by Enterprise GP Holdings L.P. on December 8, 2009).
10.33***	Agreement of Limited Partnership of EPE Unit II, L.P. dated December 5, 2006 (incorporated by reference to Exhibit 10.13 to Form 10-K filed by Enterprise Product Partners L.P. on February 28, 2007).
10.34***	First Amendment to Agreement of Limited Partnership of EPE Unit II, L.P. dated August 7, 2007 (incorporated by reference to Exhibit 10.4 to Form 10-Q filed August 8, 2007).
10.35***	Second Amendment to Agreement of Limited Partnership of EPE Unit II, L.P. dated July 1, 2008 (incorporated by reference to Exhibit 10.2 to Form 8-K filed by Enterprise GP Holdings L.P. on July 7, 2008).
10.36***	Third Amendment to Agreement of Limited Partnership of EPE Unit II, L.P. dated December 2, 2009 (incorporated by reference to Exhibit 10.2 to Form 8-K filed by Enterprise GP Holdings L.P. on December 8, 2009).
10.37***	Agreement of Limited Partnership of EPE Unit III, L.P. dated May 7, 2007 (incorporated by reference to Exhibit 10.6 to Form 8-K filed by Enterprise GP Holdings L.P. on May 10, 2007).
10.38***	First Amendment to Agreement of Limited Partnership of EPE Unit III, L.P. dated August 7, 2007 (incorporated by reference to Exhibit 10.5 to Form 10-Q filed August 8, 2007).
10.39***	Second Amendment to Agreement of Limited Partnership of EPE Unit III, L.P. dated July 1, 2008 (incorporated by reference to Exhibit 10.3 to Form 8-K filed by Enterprise GP Holdings L.P. on July 7, 2008).

10.40***	Third Amendment to Agreement of Limited Partnership of EPE Unit III, L.P. dated December 2, 2009 (incorporated by reference to Exhibit 10.3 to Form 8-K filed by Enterprise GP Holdings L.P. on December 8, 2009).
10.41	Second Amended and Restated Limited Liability Company Agreement of Mont Belvieu Caverns, LLC dated November 1, 2008 (incorporated by reference to Exhibit 10.4 to Form 10-Q filed November 10, 2008).
10.42	Purchase and Sale Agreement dated as of December 8, 2008 by and among (a) Enterprise Products Operating LLC and Enterprise GTM Holdings L.P. as Seller Parties and (b) Duncan Energy Partners L.P., DEP Holdings, LLC, DEP Operating Partnership, L.P. and DEP OLP GP, LLC as Buyer Parties (incorporated by reference to Exhibit 10.1 of Form 8-K filed December 8, 2008).
10.43	Contribution, Conveyance and Assumption Agreement dated as of December 8, 2008 by and among Duncan Energy Partners L.P., DEP OLPGP, LLC, DEP Operating Partnership, L.P., Enterprise GTM Holdings L.P. and Enterprise Holding III, L.L.C. (incorporated by reference to Exhibit 10.2 of Form 8-K filed December 8, 2008).
10.44	Third Amended and Restated Agreement of Limited Partnership of Enterprise GC, L.P. dated December 8, 2008 (incorporated by reference to Exhibit 10.3 of Form 8-K filed December 8, 2008).
10.45	Fourth Amended and Restated Agreement of Limited Partnership of Enterprise Intrastate L.P. dated December 8, 2008 (incorporated by reference to Exhibit 10.4 of Form 8-K filed December 8, 2008).
10.46	Amended and Restated Company Agreement of Enterprise Texas Pipeline LLC dated December 8, 2008 (incorporated by reference to Exhibit 10.5 of Form 8-K filed December 8, 2008).
10.47	Amended and Restated Omnibus Agreement dated December 8, 2008 among Enterprise Products Operating LLC, DEP Holdings, LLC, Duncan Energy Partners L.P., DEP OLPGP, LLC, DEP Operating Partnership, L.P., Enterprise Lou-Tex Propylene Pipeline L.P., Sabine Propylene Pipeline L.P., Acadian Gas, LLC, Mont Belvieu Caverns, LLC, South Texas NGL Pipelines, LLC, Enterprise Holding III, LLC, Enterprise Texas Pipeline LLC, Enterprise Intrastate L.P. and Enterprise GC, LP (incorporated by reference to Exhibit 10.6 of Form 8-K filed December 8, 2008).
10.48	Unit Purchase Agreement, dated as of December 8, 2008, by and between Duncan Energy Partners L.P. and Enterprise Products Operating LLC (incorporated by reference to Exhibit 10.9 of Form 8-K filed December 8, 2008).
10.49	Fifth Amended and Restated Administrative Services Agreement dated January 30, 2009 by and among EPCO, Inc., Enterprise GP Holdings L.P., EPE Holdings, LLC, Enterprise Products Partners L.P., Enterprise Products Operating L.P., Enterprise Products GP, LLC, Enterprise Products OLPGP, Inc., DEP Holdings, LLC, Duncan Energy Partners L.P., DEP Operating Partnership, L.P., TEPPCO Partners, L.P., Texas Eastern Products Pipeline Company, LLC, TE Products Pipeline Company, LLC, TEPPCO Midstream Companies, LLC, TCTM, L.P. and TEPPCO GP, Inc. (incorporated by reference to Exhibit 10.1 to Form 8-K filed by Enterprise Products Partners L.P. on February 5, 2009).
10.50	Common Unit Purchase Agreement, dated June 15, 2009, by and among Enterprise Products Operating LLC and Enterprise GTM Holdings L.P. as Sellers and Duncan Energy Partners L.P. as Buyer (incorporated by reference to Exhibit 1.2 to Form 8-K filed June 18, 2009).
10.51	Revolving Credit Agreement, dated as of January 5, 2007, among Duncan Energy Partners L.P., as Borrower, the Lenders Party Thereto, Wachovia Bank, National Association, as Administrative Agent, Issuing Bank and Swingline Lender, The Bank of Nova Scotia and Citibank, N.A., as Co-Syndication Agents, JPMorgan Chase Bank, N.A. and Mizuho Corporate Bank, Ltd., as Co-Documentation Agents, and Wachovia Capital Markets, LLC, The Bank of Nova Scotia and Citigroup Global Markets Inc., as Joint Lead Arrangers and Joint Book Runners (incorporated by reference to Exhibit 10.20 to Amendment No. 2 to Form S-1 Registration Statement (Reg. No. 333-138371) filed January 12, 2007).
10.52	First Amendment to Revolving Credit Agreement, dated as of June 30, 2007, among Duncan Energy Partners L.P., as Borrower, the Lenders Party Thereto. Wachovia Bank, National Association, as Administrative Agent, The Bank of Nova Scotia and Citibank, N.A., as Co-

	Syndication Agents, JPMorgan Chase Bank, N.A. and Mizuho Corporate Bank, Ltd., as Co-Documentation Agents, and Wachovia Capital Markets, LLC, The Bank of Nova Scotia and Citigroup Global Markets Inc., as Joint Lead Arrangers and Joint Book Runners (incorporated by reference to Exhibit 4.2 to Form 10-Q filed August 8, 2007).
10.53	Term Loan Agreement, dated as of April 18, 2008, among Duncan Energy Partners L.P., as Borrower, the Lenders Party Thereto, Wachovia Bank, National Association, as Administrative Agent, Suntrust Bank and The Bank of Nova Scotia, as Co-Syndication Agents, Mizuho Corporate Bank, Ltd. and The Royal Bank of Scotland plc, as Co-Documentation Agents, and Wachovia Capital Markets, LLC, SunTrust Robinson Humphrey, a division of SunTrust Capital Markets, Inc. and The Bank of Nova Scotia, as Joint Lead Arrangers and Joint Book Runners (incorporated by reference to Exhibit 10.7 of Form 8-K filed December 8, 2008).
10.54	First Amendment to Term Loan Agreement, dated as of July 11, 2008, among Duncan Energy Partners L.P., as Borrower, the Lenders Party Thereto, Wachovia Bank, National Association, as Administrative Agent, Suntrust Bank and The Bank of Nova Scotia, as Co-Syndication Agents, Mizuho Corporate Bank, Ltd. and The Royal Bank of Scotland plc, as Co-Documentation Agents, and Wachovia Capital Markets, LLC, SunTrust Robinson Humphrey, a division of SunTrust Capital Markets, Inc. and The Bank of Nova Scotia, as Joint Lead Arrangers and Joint Book Runners (incorporated by reference to Exhibit 10.8 of Form 8-K filed December 8, 2008).
12.1**	Computation of ratio of earnings to fixed charges for each of the five years ended December 31, 2009, 2008, 2007, 2006 and 2005.
21.1**	List of Subsidiaries as of February 1, 2010.
23.1#	Consent of Deloitte & Touche LLP.
31.1#	Sarbanes-Oxley Section 302 certification of W. Randall Fowler for Duncan Energy Partners L.P. for the December 31, 2009 Annual Report on Form 10-K/A.
31.2#	Sarbanes-Oxley Section 302 certification of Bryan F. Bulawa for Duncan Energy Partners L.P. for the December 31, 2009 Annual Report on Form 10-K/A.
32.1#	Section 1350 certification of W. Randall Fowler for the December 31, 2009 Annual Report on Form 10-K/A.
32.2#	Section 1350 certification of Bryan F. Bulawa for the December 31, 2009 Annual Report on Form 10-K/A.

* With respect to exhibits incorporated by reference to Exchange Act filings, the Commission file numbers for Enterprise Products Partners L.P. and Enterprise GP Holdings L.P. are 1-14323 and 1-32610, respectively.

** These exhibits were filed with our Original Filing.

*** Identifies management contract and compensatory plan arrangements.

\# Filed with this report.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized on May 21, 2010.

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

By: DEP Holdings, LLC, as General Partner

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

DUNCAN ENERGY PARTNERS L.P.
INDEX TO FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of DEP Holdings, LLC and
Unitholders of Duncan Energy Partners L.P.
Houston, Texas

We have audited the accompanying consolidated balance sheets of Duncan Energy Partners L.P. and subsidiaries (the "Company") as of December 31, 2009 and 2008, and the related statements of consolidated operations, comprehensive income, cash flows, and equity for each of the three years in the period ended December 31, 2009. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements based on our audits.

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

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Duncan Energy Partners L.P. and subsidiaries at December 31, 2009 and 2008, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2009, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2009, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 1, 2010 expresses an unqualified opinion on the Company's internal control over financial reporting.

As discussed in Note 1 to the Consolidated Financial Statements, the accompanying financial statements have been prepared from the separate records maintained by Enterprise Products Partners L.P. or affiliates and may not necessarily be indicative of the conditions that would have existed or the results of operations if the Company had been operated as an unaffiliated entity.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
March 1, 2010
(May 21, 2010 as to the effect of the restatement discussed in Note 21)

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

	December 31, 2009	December 31, 2008
ASSETS		
Current assets		
Cash and cash equivalents	$ 3.9	$ 13.0
Accounts receivable – trade, net of allowance for doubtful accounts	77.7	117.3
Accounts receivable – related parties	54.5	3.3
Gas imbalance receivables	9.8	35.7
Inventories	10.5	28.0
Prepaid and other current assets	9.8	4.3
Total current assets	166.2	201.6
Property, plant and equipment, net	4,549.6	4,330.2
Investments in Evangeline	5.6	4.5
Intangible assets, net of accumulated amortization of $42.6 at December 31, 2009 and $34.1 at December 31, 2008	43.8	52.3
Goodwill	4.9	4.9
Other assets	0.7	1.2
Total assets	$ 4,770.8	$ 4,594.7
LIABILITIES AND EQUITY		
Current liabilities		
Accounts payable – trade	$ 54.5	$ 45.2
Accounts payable – related parties	13.6	48.5
Accrued product payables	59.9	109.7
Accrued property taxes	9.1	8.3
Accrued taxes – other	8.4	8.3
Other current liabilities	18.9	33.3
Total current liabilities	164.4	253.3
Long-term debt (see Note 11)	457.3	484.3
Deferred tax liabilities	5.8	5.7
Other long-term liabilities	6.4	7.2
Commitments and contingencies		
Equity:		
Duncan Energy Partners L.P. partners' equity: (see Note 12)		
Limited partners		
Common units (57,676,987 common units outstanding at December 31, 2009 and 20,343,100 common units outstanding at December 31, 2008)	766.6	308.2
Class B units (37,333,887 Class B units outstanding at December 31, 2008)	--	453.8
General partner	0.2	0.4
Accumulated other comprehensive loss	(5.4)	(9.6)
Total Duncan Energy Partners L.P. partners' equity	761.4	752.8
Noncontrolling interest in subsidiaries: (see Note 13)		
DEP I Midstream Businesses – Parent	487.3	478.4
DEP II Midstream Businesses – Parent	2,888.2	2,613.0
Total noncontrolling interest	3,375.5	3,091.4
Total equity	4,136.9	3,844.2
Total liabilities and equity	$ 4,770.8	$ 4,594.7

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

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

	For Year Ended December 31,		
	2009	2008	2007
Revenues			
Third parties	$ 492.0	$ 856.4	$ 759.3
Related parties	487.3	741.7	461.0
Total revenues (see Note 14)	979.3	1,598.1	1,220.3
Costs and Expenses			
Operating costs and expenses:			
Third parties	749.0	1,167.7	1,066.7
Related parties	159.3	345.1	104.3
Total operating costs and expenses	908.3	1,512.8	1,171.0
General and administrative costs:			
Third parties	0.3	3.4	1.7
Related parties	10.9	14.9	11.4
Total general and administrative costs	11.2	18.3	13.1
Total costs and expenses	919.5	1,531.1	1,184.1
Equity in income of Evangeline	1.1	0.9	0.2
Operating income	60.9	67.9	36.4
Other income (expense)			
Interest expense	(14.0)	(12.0)	(9.3)
Other, net	0.2	0.5	0.7
Other expense, net	(13.8)	(11.5)	(8.6)
Income before provision for income taxes	47.1	56.4	27.8
Provision for income taxes	(1.3)	(1.1)	(4.2)
Net income	45.8	55.3	23.6
Net loss (income) attributable to noncontrolling interest: (see Note 13)			
DEP I Midstream Businesses - Parent	(15.3)	(11.4)	(20.0)
DEP II Midstream Businesses - Parent	60.6	4.0	--
Total net loss (income) attributable to noncontrolling interest	45.3	(7.4)	(20.0)
Net income attributable to Duncan Energy Partners L.P. (see Note 1)	$ 91.1	$ 47.9	$ 3.6
Allocation of net income attributable to Duncan Energy Partners L.P.: (see Note 1)			
Duncan Energy Partners L.P.:			
Limited partners' interest in net income	$ 90.5	$ 27.8	$ 18.8
General partner interest in net income	$ 0.6	$ 0.5	$ 0.4
Former owners of DEP I Midstream Businesses		n/a	$ 5.0
Former owners of DEP II Midstream Businesses		$ 19.6	$ (20.6)
Basic and diluted earnings per unit (see Note 16)	$ 1.57	$ 1.22	$ 0.93

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

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

	For Year Ended December 31, 2009	2008	2007
Net income	$ 45.8	$ 55.3	$ 23.6
Other comprehensive income (loss):			
Cash flow hedges:			
Interest rate derivative instrument losses during period	(2.5)	(8.0)	(3.3)
Reclassification adjustment for (gains) losses included in net income related to interest rate derivative instruments	6.6	2.0	(0.3)
Commodity derivative instrument losses during period	--	(0.7)	(0.1)
Reclassification adjustment for losses included in net income related to commodity derivative instruments	--	0.7	0.1
Total other comprehensive income (loss)	4.1	(6.0)	(3.6)
Comprehensive income	49.9	49.3	20.0
Comprehensive loss (income) attributable to noncontrolling interest:			
DEP I Midstream Businesses – Parent	(15.3)	(11.4)	(20.0)
DEP II Midstream Businesses – Parent	60.6	4.0	--
Total comprehensive loss (income) attributable to noncontrolling interest	45.3	(7.4)	(20.0)
Comprehensive loss (income) allocated to former owners of DEP II Midstream Businesses	--	(19.6)	20.6
Comprehensive income attributable to Duncan Energy Partners L.P.	$ 95.2	$ 22.3	$ 20.6

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

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

	For Year Ended December 31, 2009	2008	2007
Operating activities:			
Net income	$ 45.8	$ 55.3	$ 23.6
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation, amortization and accretion	188.3	167.8	175.6
Equity in income of Evangeline	(1.1)	(0.9)	(0.2)
Gain on sale of assets and related transactions	(0.5)	(0.5)	(0.1)
Deferred income tax expense	--	0.3	3.8
Non-cash asset impairment	4.2	--	--
Changes in fair market value of derivative instruments	(0.2)	(0.1)	0.2
Net effect of changes in operating accounts (see Note 19)	(34.9)	(1.8)	14.2
Cash flows provided by operating activities	201.6	220.1	217.1
Investing activities:			
Capital expenditures	(389.1)	(759.5)	(340.1)
Contributions in aid of construction costs	5.7	9.9	10.0
Proceeds from sale of assets and related transactions	0.9	0.9	12.6
Cash used for business combinations	(0.7)	--	(35.0)
Other, including loans to affiliates	(45.6)	(0.1)	0.1
Cash used in investing activities	(428.8)	(748.8)	(352.4)
Financing activities:			
Repayments of debt	(103.2)	(114.7)	(114.0)
Borrowings under debt agreements	76.2	398.9	314.0
Debt issuance costs	(0.4)	(1.6)	(0.5)
Net proceeds from Duncan Energy Partners’ common unit offerings	137.4	0.5	290.5
Common units repurchased from EPO and subsequently retired	(137.4)	--	--
Cash distributions to Duncan Energy Partners’ unitholders and general partner	(88.9)	(34.4)	(21.8)
Cash distributions to noncontrolling interest	(51.6)	(318.1)	(491.0)
Cash contributions from noncontrolling interest	386.0	183.3	105.0
Net cash contributions from former owners of the DEP I Midstream Businesses	--	--	8.5
Net cash contributions from former owners of the DEP II Midstream Businesses	--	425.6	46.8
Cash provided by financing activities	218.1	539.5	137.5
Net changes in cash and cash equivalents	(9.1)	10.8	2.2
Cash and cash equivalents, beginning of period	13.0	2.2	--
Cash and cash equivalents, end of period	$ 3.9	$ 13.0	$ 2.2

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

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

	Former Owners		Duncan Energy Partners			Noncontrolling	
	DEP I Midstream Businesses	DEP II Midstream Businesses	Limited Partners	General Partner	AOCI	Interest in Subsidiaries	Total
Balance, January 1, 2007	$ 725.8	$ 2,853.8	$ --	$ --	$ --	$ --	$ 3,579.6
Transactions prior to the DEP I dropdown effective February 1, 2007:							
Net income (loss)	5.0	(0.3)	--	--	--	--	4.7
Net cash contributions (distributions) to former owners	8.5	(8.8)	--	--	--	--	(0.3)
Balance, January 31, 2007	739.3	2,844.7	--	--	--	--	3,584.0
Transactions in connection with Duncan Energy Partners' initial public offering and the DEP I drop down effective February 1, 2007:							
Adjustment for liabilities of DEP I Midstream Businesses not transferred to Duncan Energy Partners	2.7	--	--	--	--	--	2.7
Retention by noncontrolling interest of ownership interests	(252.3)	--	--	--	--	252.3	--
Allocation of equity in the DEP I Midstream Businesses to Duncan Energy Partners	(489.7)	--	479.9	9.8	--	--	--
Net proceeds from Duncan Energy Partners' initial public offering	--	--	290.5	--	--	--	290.5
Cash distribution to noncontrolling interest at time of initial public offering	--	--	(450.3)	(9.2)	--	--	(459.5)
Balance, February 1, 2007	$ --	2,844.7	320.1	0.6	--	252.3	3,417.7
Net income (loss)		(20.3)	18.8	0.4	--	20.0	18.9
Amortization of equity awards		--	0.2	--	--	--	0.2
Cash contributions from former owners		55.6	--	--	--	--	55.6
Cash distributions to partners		--	(21.4)	(0.4)	--	--	(21.8)
Cash contributions from noncontrolling interest		--	--	--	--	105.0	105.0
Cash distributions to noncontrolling interest		--	--	--	--	(31.5)	(31.5)
Cash flow hedges		--	--	--	(3.6)	--	(3.6)
Other		0.1	--	--	--	9.4	9.5
Balance, December 31, 2007		2,880.1	317.7	0.6	(3.6)	355.2	3,550.0
Transactions prior to the DEP II drop down on December 8, 2008:							
Net income – January 1, 2008 through December 7, 2008		19.6	21.1	0.4	--	12.0	53.1
Amortization of equity awards		--	0.2	--	--	--	0.2
Cash contributions from former owner		425.6	--	--	--	--	425.6
Cash contributions from noncontrolling interest		--	--	--	--	161.6	161.6
Cash distributions to noncontrolling interest		--	--	--	--	(37.3)	(37.3)
Cash distributions to partners		--	(33.7)	(0.7)	--	--	(34.4)
Cash flow hedges		--	--	--	(0.3)	--	(0.3)
Other		0.2	--	--	--	(12.5)	(12.3)
Balance, December 7, 2008		3,325.5	305.3	0.3	(3.9)	479.0	4,106.2
Transactions in connection with the DEP II drop down on December 8, 2008:							
Retention by noncontrolling interest of ownership interests		(2,595.5)	--	--	--	2,595.5	--
Allocation of equity in the DEP II Midstream Businesses to Duncan Energy Partners		(730.0)	730.0	--	--	--	--
Cash distribution paid to noncontrolling interest at DEP II drop down		--	(280.5)	--	--	--	(280.5)
Net proceeds from the issuance of common units		--	0.5	--	--	--	0.5
Balance, December 8, 2008		$ --	755.3	0.3	(3.9)	3,074.5	3,826.2
Net income (loss) – December 8, 2008 through December 31, 2008			6.7	0.1	--	(4.6)	2.2
Cash contributions from noncontrolling interest			--	--	--	21.7	21.7
Cash distributions to noncontrolling interest			--	--	--	(0.3)	(0.3)
Cash flow hedges			--	--	(5.7)	--	(5.7)
Other			--	--	--	0.1	0.1
Balance, December 31, 2008			762.0	0.4	(9.6)	3,091.4	3,844.2
Net income (loss)			90.5	0.6	--	(45.3)	45.8
Amortization of equity awards			2.2	--	--	--	2.2
Net proceeds from Duncan Energy Partners' common unit offerings			137.4	--	--	--	137.4
Cash contributions from noncontrolling interest			--	--	--	386.0	386.0
Cash distributions to noncontrolling interest			--	--	--	(51.6)	(51.6)
Cash distributions to unitholders and general partner			(88.1)	(0.8)	--	--	(88.9)
Common units repurchased from EPO and retired (see Note 12)			(137.4)	--	--	--	(137.4)

Cash flow hedges	--	--	4.2	--	4.2
Other	--	--	--	(5.0)	(5.0)
Balance, December 31, 2009	$ 766.6	$ 0.2	$ (5.4)	$ 3,375.5	$ 4,136.9

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

DUNCAN ENERGY PARTNERS

NOTES TO 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 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. References to “DEP OLP” mean DEP Operating Partnership, L.P., which is a wholly owned subsidiary of Duncan Energy Partners through which Duncan Energy Partners conducts substantially all of its business.

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

References to “TEPPCO” and “TEPPCO GP” mean TEPPCO Partners, L.P. and Texas Eastern Products Pipeline Company, LLC (which is the general partner of TEPPCO), respectively, prior to their mergers with subsidiaries of Enterprise Products Partners (the “TEPPCO Merger”). On October 26, 2009, Enterprise Products Partners completed the mergers with TEPPCO and TEPPCO GP. On October 27, 2009, Enterprise Products Partners’ TEPPCO and TEPPCO GP equity interests were contributed to EPO, and TEPPCO and TEPPCO GP became wholly owned subsidiaries of EPO.

References to “Enterprise GP Holdings” mean Enterprise GP Holdings L.P., a publicly traded Delaware limited partnership, the units of which are listed on the NYSE under the ticker symbol “EPE.” Enterprise GP Holdings owns EPGP. The general partner of Enterprise GP Holdings is EPE Holdings, LLC (“EPE Holdings”), a wholly owned subsidiary of Dan Duncan LLC, all of the membership interests of which are owned by Dan L. Duncan.

References to “Energy Transfer Equity” mean the business and operations of Energy Transfer Equity, L.P. and its consolidated subsidiaries, which include Energy Transfer Partners, L.P. (“ETP”). Energy Transfer Equity is a publicly traded Delaware limited partnership, the common units of which are listed on the NYSE under the ticker symbol “ETE.” ETP is a publicly traded Delaware limited partnership, the common units of which are listed on the NYSE under the ticker symbol “ETP.” The general partner of Energy Transfer Equity is LE GP, LLC (“LE GP”).

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

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

Within the context of our financial information, references to "former owners" mean EPO's ownership interests in the DEP I and DEP II Midstream Businesses prior to the effective date of the related drop down transactions.

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 "EPCO" mean Enterprise Products Company (formerly EPCO, Inc.) and its privately held affiliates. We, Enterprise Products Partners, EPO, DEP GP, EPGP, Enterprise GP Holdings and EPE Holdings are affiliates under the common control of Dan L. Duncan, the Group Co-Chairman and controlling shareholder of EPCO.

References to "Employee Partnerships" mean EPE Unit L.P. ("EPE Unit I"), EPE Unit II, L.P. ("EPE Unit II"), EPE Unit III, L.P. ("EPE Unit III"), Enterprise Unit L.P. ("Enterprise Unit") and EPCO Unit L.P. ("EPCO Unit"), collectively, all of which are privately held affiliates of EPCO.

Note 1. Partnership Organization, Primary Operations and Basis of Financial Statement Presentation

Duncan Energy Partners is a publicly traded Delaware limited partnership, the common units of which are listed on the NYSE under the ticker symbol "DEP." Duncan Energy Partners is engaged in the business of: (i) natural gas liquids ("NGLs") transportation, fractionation and marketing; (ii) storage of NGL and petrochemical products; (iii) transportation of petrochemical products; and (iv) the gathering, transportation, marketing and storage of natural gas.

At December 31, 2009, Duncan Energy Partners was owned 99.3% by its limited partners and 0.7% by its general partner, DEP GP, which is a wholly owned subsidiary of EPO. At December 31, 2009, EPO owned approximately 58.6% of Duncan Energy Partners' limited partner interests and 100% of DEP GP. DEP GP is responsible for managing the business and operations of Duncan Energy Partners.

A privately held affiliate, EPCO, provides all of our employees and certain administrative services to the partnership.

The following information summarizes the businesses acquired and consideration we provided 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.

As consideration for these equity interests, we paid $459.5 million in cash and issued 5,351,571 common units to EPO. The cash portion of this consideration was financed with $198.9 million in borrowings under our $300.0 million unsecured revolving credit facility (the "Revolving Credit Facility") and $260.6 million of the $290.5 million of net proceeds from our initial public offering. The following is a brief description of the assets and operations of the DEP I Midstream Businesses:

- § Mont Belvieu Caverns owns 34 underground salt dome storage caverns located in Mont Belvieu, Texas, having an NGL and related product storage capacity of approximately 100 million barrels

("MMBbls"), and a brine system with approximately 20 MMBbls of above ground storage capacity and two brine production wells.

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

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

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

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

DEP II Drop Down

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

§ Enterprise GC operates and owns: (i) two NGL fractionation facilities, the Shoup and Armstrong, located in south Texas; (ii) a 1,020-mile NGL pipeline system located in south Texas; and (iii) 1,112 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 190-mile TPC Offshore gathering system located in south Texas.

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

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

See "Noncontrolling Interest – DEP II Midstream Businesses – Parent" under Note 13 and "Significant Relationships and Agreements with EPO – Company and Limited Partnership Agreements – DEP II Midstream Businesses" under Note 15 for additional information.

Generally, to the extent that the DEP II Midstream Businesses collectively generate cash sufficient to pay distributions to EPO and us, such cash will be distributed first to us (based on an initial defined investment of $730.0 million) and then to EPO in amounts sufficient to generate an aggregate initial annualized return on their respective investments of 11.85%. Effective January 1, 2010, the annualized return increased by 2.0% to 12.087%. Distributions in excess of these amounts will be distributed 98% to

EPO and 2% to us. Income and loss of the DEP II Midstream Businesses are first allocated to EPO and us based on each entity's percentage interest of 77.4% and 22.6%, respectively, and then in a manner that in part follows the cash distributions.

See Note 13 for detailed information regarding EPO's noncontrolling interest in the DEP I and DEP II Midstream Businesses.

Basis of Financial Statement Presentation

Duncan Energy Partners, DEP GP, DEP OLP, Enterprise Products Partners (including EPO and its consolidated subsidiaries) and EPCO and affiliates are under common control of Dan L. Duncan, the Group Co-Chairman and controlling shareholder of EPCO. Prior to the drop down of controlling interests in the DEP I and DEP II Midstream Businesses to Duncan Energy Partners, EPO owned these businesses and directed their respective activities for all periods presented (to the extent such businesses were in existence during such periods). Each of the drop down transactions was accounted for at EPO's historical costs as a reorganization of entities under common control in a manner similar to a pooling of interests. On a standalone basis, Duncan Energy Partners did not own any assets prior to the completion of its initial public offering on February 5, 2007 (February 1, 2007 for financial accounting and reporting purposes).

Our consolidated financial statements include the accounts of Duncan Energy Partners, and prior to the DEP I and DEP II drop down transactions, the assets, liabilities and operations contributed to us by EPO upon the closing of these drop down transactions. Our financial statements have been prepared in accordance with generally accepted accounting principles ("GAAP") in the United States. The financial statements of the DEP I and DEP II Midstream Businesses were prepared from the separate records maintained by EPO and may not necessarily be indicative of the conditions that would have existed or the results of operations if the DEP I and DEP II Midstream Businesses had operated as unaffiliated entities. All intercompany balances and transacti ons have been eliminated in consolidation. Transactions between EPO and us have been identified in our consolidated financial statements as transactions between affiliates.

Our consolidated financial statements for the year ended December 31, 2007 reflect the following:

§ Combined financial information of the DEP I Midstream Businesses for the month of January 2007. The results of operations and cash flows of the DEP I Midstream Businesses for this one-month period are allocated to the former owners of these businesses that are under common control with Duncan Energy Partners. On February 5, 2007, these businesses were contributed to Duncan Energy Partners in the DEP I drop down transaction; therefore, the DEP I Midstream Businesses were consolidated subsidiaries of Duncan Energy Partners for the eleven months ended December 31, 2007. For financial accounting and reporting purposes, the effective date of the DEP I drop down transaction is February 1, 2007. EPO's retained ownership in the DEP I Midstream Businesses (following the drop down transaction) is presented in ou r consolidated financial statements as "Noncontrolling interest in subsidiaries – DEP I Midstream Businesses – Parent."

§ Combined financial information of the DEP II Midstream Businesses for the year ended December 31, 2007. The results of operations and cash flows of the DEP II Midstream Businesses for this twelve-month period are allocated to the former owners of these businesses that are under common control with Duncan Energy Partners.

Our consolidated financial statements for the year ended December 31, 2008 reflect the following:

§ Combined financial information of the DEP II Midstream Businesses from January 1, 2008 through December 7, 2008. The results of operations and cash flows of the DEP II Midstream Businesses for this period are allocated to the former owners of these businesses that are under common control with Duncan Energy Partners.

§ Consolidated financial information for Duncan Energy Partners for the twelve months ended December 31, 2008, including the results of operations and cash flows for the DEP II Midstream Businesses following completion of the DEP II drop down transaction. On December 8, 2008, the DEP II Midstream Businesses were contributed to Duncan Energy Partners in the DEP II drop down transaction; therefore, the DEP II Midstream Businesses became consolidated subsidiaries of Duncan Energy Partners on this date. EPO's retained ownership in the DEP II Midstream Businesses (following the December 8, 2008 drop down transaction) is presented in our consolidated financial statements as "Noncontrolling interest in subsidiaries – DEP II Midstream Businesses – Parent."

Note 2. Summary of Significant Accounting Policies

Allowance for Doubtful Accounts

Our allowance for doubtful accounts balance is determined based on specific identification and estimates of future uncollectible accounts, as appropriate. Our procedure for recording an allowance for doubtful accounts is based on: (i) our historical experience; (ii) the financial stability of our customers; and (iii) the levels of credit granted to customers. In addition, we may also increase the allowance account in response to the specific identification of customers involved in bankruptcy proceedings and those experiencing other financial difficulties. On a routine basis, we review estimates associated with the allowance for doubtful accounts to ensure we have recorded sufficient reserves to cover potential losses. The followi ng financial statement schedule presents changes in our allowance for doubtful account balances for the periods indicated:

	For Year Ended December 31,		
	2009	2008	2007
Balance at beginning of period	$ *	$ *	$ 0.4
Charges to expense	--	--	--
Deductions	*	--	(0.4)
Balance at end of period	$ *	$ *	$ *

* Amounts are negligible and less than $0.1 million.

From time to time, we may also establish an allowance for uncollectible natural gas imbalances based on specific identification of accounts. At December 31, 2009 and 2008, our allowance for uncollectible natural gas imbalances was zero. At December 31, 2007, the balance was $5.4 million.

Cash and Cash Equivalents

Cash and cash equivalents represent unrestricted cash on hand and highly liquid investments with original maturities of less than three months from the date of purchase.

The DEP I and DEP II Midstream Businesses operated within the EPO cash management program prior to their respective drop down transaction dates of February 1, 2007 and December 8, 2008. For purposes of presentation in our Statements of Consolidated Cash Flows, cash flows provided by (or used in) financing activities during the pre-drop down timeframes represent transfers of excess cash from the DEP I and/or DEP II Midstream Businesses to their former owners in amounts equal to any excess of net cash flow provided by operating activities over cash used in investing activities. Such transfers of excess cash are shown as permanent distributions to former owners on our Statements of Consolidated Equity. Conversely, if cash used in investing activities was gre ater than net cash flow provided by operating activities, then a deemed permanent contribution by the former owners was recognized. As a result, our financial statements do not reflect cash balances for the DEP I and DEP II Midstream Businesses prior to their respective drop down transaction dates. Following the DEP I and DEP II drop down transactions, the respective businesses ceased participation in the EPO cash management program and maintain cash balances separately from affiliates.

Consolidation Policy

Our consolidated financial statements include our accounts and those of our majority-owned subsidiaries in which we have a controlling interest, after the elimination of all intercompany accounts and transactions. We evaluate our financial interests in business enterprises to determine if they represent variable interest entities where we are the primary beneficiary. If such criteria are met, we consolidate the financial statements of such businesses with those of our own. Parent company ownership interests in our controlled subsidiaries are presented as noncontrolling interests. See Note 13 for information regarding noncontrolling interest.

If an entity is organized as a limited partnership or limited liability company and maintains separate ownership accounts, we account for our investment using the equity method if our ownership interest is between 3% and 50% and we exercise significant influence over the investee's operating and financial policies. For all other types of investments, we apply the equity method of accounting if our ownership interest is between 20% and 50% and we exercise significant influence over the investee's operating and financial policies. In consolidation, we eliminate our proportionate share of profits and losses from transactions with equity method unconsolidated affiliates to the extent such amounts remain on our Consolidated Balance Sheets (or those of our equ ity method investments) in inventory or similar accounts.

If our ownership interest in an investee does not provide us with either control or significant influence over the investee, we would account for the investment using the cost method. We currently do not have any investments accounted for using the cost method.

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. Our management and legal counsel evaluate such contingent liabilities, and such evaluations inherently involve 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.

If the assessment of a contingency indicates that it is probable that a material loss has been incurred and the amount of liability can be estimated, then the estimated liability would be accrued in our financial statements. If the assessment indicates that a potential material loss contingency is not probable but is reasonably possible, or is probable but cannot be estimated, then the nature of the contingent liability, together with an estimate of the range of possible loss if determinable, is disclosed.

Loss contingencies considered remote are generally not disclosed unless they involve guarantees, in which case the guarantees would be disclosed.

Current Assets and Current Liabilities

We present, as individual captions in our Consolidated Balance Sheets, all components of current assets and current liabilities that exceed five percent of total current assets and liabilities, respectively.

Deferred Revenue

Amounts billed in advance of the period in which the service is rendered or product delivered are recorded as deferred revenue. At December 31, 2009 and 2008, deferred revenues totaled $4.5 million and $7.2 million, respectively, and were recorded as a component of other current and long-term liabilities as appropriate on our Consolidated Balance Sheets. See Note 4 for additional information regarding our revenue recognition policies.

Derivative Instruments

We use derivative instruments such as swaps, forwards and other 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 also apply the normal purchases/normal sales exception for certain of our derivative instruments, which precludes the recognition of changes in mark-to-market value for these items on the balance sheet or income statement. ; Revenues and costs for these transactions are recognized when volumes are physically delivered or received. See Note 6 for additional information regarding our derivative instruments and related hedging activities.

Earnings per Unit

See Note 16 for more information regarding our earnings per unit.

Environmental Costs

Environmental costs for remediation are accrued based on estimates of known remediation requirements. Such accruals are based on management's estimate of the ultimate cost to remediate a site and are adjusted as further information and circumstances develop. Those estimates may change substantially depending on information about the nature and extent of contamination, appropriate remediation technologies and regulatory approvals. Expenditures to mitigate or prevent future environmental contamination are capitalized. Ongoing environmental compliance costs are charged to expense as incurred. In accruing for environmental remediation liabilities, costs of future expenditures for environmental remediation are not discounted to their present value , unless the amount and timing of the expenditures are fixed or reliably determinable. At December 31, 2009, none of our estimated environmental remediation liabilities were discounted to present value since the ultimate amount and timing of cash payments for such liabilities were not readily determinable.

The following table presents the activity of our environmental reserves for the periods indicated:

	For Year Ended December 31,		
	2009	**2008**	**2007**
Balance at beginning of period	$ 0.6	$ 17.8	$ 20.7
Charges to expense	0.1	0.5	0.3
Deductions (1)	(0.2)	(17.7)	(3.2)
Balance at end of period	$ 0.5	$ 0.6	$ 17.8

(1) The $17.7 million deduction in 2008 in the reserve balance is partially comprised of a $5.0 million reduction in the reserve based on revised estimates of future remediation costs and a remaining $6.3 million reserve retained by EPO in connection with the DEP II drop down transaction. In addition, we spent approximately $5.4 million for the remediation of mercury site contamination in 2008.

Equity Awards

See Note 5 for information regarding our accounting for equity awards.

Estimates

Preparing our financial statements in conformity with GAAP requires management to make estimates and assumptions that affect: (i) reported amounts of assets and liabilities; (ii) disclosure of contingent assets and liabilities at the date of the financial statements; and (iii) the reported amounts of revenues and expenses during a given period. Our actual results could differ from these estimates. On an ongoing basis, management reviews its estimates based on currently available information. Changes in facts and circumstances may result in revised estimates.

Fair Value Information

Cash and cash equivalents, accounts receivable, accounts payable, accrued expenses and other current liabilities are carried at amounts which reasonably approximate their fair values due to their short-term nature. The carrying amounts of our variable-rate debt obligations reasonably approximate their fair values due to their variable interest rates. See Note 6 for additional fair value information associated with our derivative instruments.

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

	December 31, 2009		December 31, 2008	
Financial Instruments	**Carrying Value**	**Fair Value**	**Carrying Value**	**Fair Value**
Financial assets:				
Cash and cash equivalents	$ 3.9	$ 3.9	$ 13.0	$ 13.0
Accounts receivable	142.0	142.0	156.3	156.3
Financial liabilities:				
Accounts payable and accrued expenses	$ 145.5	$ 145.5	$ 220.0	$ 220.0
Other current liabilities	18.9	18.9	33.3	33.3
Variable-rate revolving credit facility	175.0	175.0	202.0	202.0
Variable-rate term loan	282.3	282.3	282.3	282.3

Impairment Testing for Goodwill

Our goodwill amounts are assessed for impairment (i) on a routine annual basis as of January 1 or (ii) when impairment indicators are present. If such indicators occur (e.g., the loss of a significant customer, economic obsolescence of plant assets, etc.), the estimated fair value of the reporting unit to which the goodwill is assigned is determined and compared to its book value. If the fair value of the reporting unit exceeds its book value including associated goodwill amounts, the goodwill is considered to be unimpaired and no impairment charge is required. If the fair value of the reporting unit is less than its book value including associated goodwill amounts, a charge to earnings is recorded to reduce the carrying value of the goodwill to its impli ed fair value. We have not recognized any impairment losses related to goodwill for any of the periods presented. See Note 10 for additional information regarding our goodwill.

Impairment Testing for Long-Lived Assets

Long-lived assets (including intangible assets with finite useful lives and property, plant and equipment) are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of such assets may not be recoverable.

Long-lived assets with carrying values that are not expected to be recovered through future cash flows are written down to their estimated fair values. The carrying value of a long-lived asset is deemed not recoverable if it exceeds the sum of undiscounted cash flows expected to result from the use and eventual disposition of the asset. If the asset carrying value exceeds the sum of its undiscounted cash flows, a non-cash asset impairment charge equal to the excess of the asset's carrying value over its estimated fair value is recorded. Fair value is defined as the amount at which an asset or liability could be bought or settled in an arm's length transaction. We measure fair value using market price indicators or, in the absence of such data, appropriate valuation techniques. See Note 6 for information regarding impairment charges recorded during 2009.

Impairment Testing for Unconsolidated Affiliate

We evaluate our equity method investment for impairment whenever events or changes in circumstances indicate that there is a potential loss in value of the investment (other than a temporary decline). Examples of such events or changes in circumstances include continuing operating losses of the entity and/or long-term negative changes in the entity's industry. In the event we determine that the loss in value of an investment is other than a temporary decline, we record a charge to equity earnings to adjust the carrying value of the investment to its estimated fair value. We had no such impairment charges during the periods presented.

Income Taxes

Provision for income taxes is primarily applicable to our state tax obligations under the Revised Texas Franchise Tax (the "Texas Margin Tax"). In general, legal entities that conduct business in Texas are subject to the Texas Margin Tax. Such amounts are considered immaterial to our financial statements.

Since we are structured as a pass-through entity, we are not subject to federal income taxes. As a result, our partners are individually responsible for paying federal income taxes on their share of our taxable income. Deferred income tax assets and liabilities are recognized for temporary differences between the assets and liabilities of our tax paying entities for financial reporting and tax purposes.

We recognize the tax effects of any uncertain tax positions we may adopt, if the position taken by us is more likely than not sustainable. If a tax position meets such criteria, the tax effect to be recognized by us would be the largest amount of benefit with more than a 50% chance of being realized upon settlement. We have not taken any uncertain tax positions as defined by the Financial Accounting Standards Board's ("FASB") accounting guidance on income taxes.

Inventories

Our inventory consists of natural gas volumes that are used either for operational system balancing or held in connection with forward sales contracts. We occasionally recognize lower of average cost or market ("LCM") adjustments when the historical cost of our forward sales inventory exceeds its net realizable value. These non-cash adjustments are recorded as a component of cost of sales within operating costs and expenses. The capitalized cost of our inventory held in connection with forward sales contracts includes shipping and handling charges that are directly related to such volumes. As volumes are delivered out of inventory, the cost of such inventory is charged to cost of sales, which is a component of operating costs and ex penses. Transportation and handling fees associated with products we deliver to customers are charged to operating costs and expenses as incurred. The 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. When such volumes are delivered out of inventory, the average cost of these volumes is charged against our accrued gas imbalance payables. See Note 7 for additional information regarding our inventories.

Natural Gas Imbalances

In the natural gas pipeline transportation business, imbalances frequently result from differences in natural gas volumes received from and delivered to our customers. Such differences occur when a customer delivers more or less gas into our pipelines than is physically redelivered back to them during a particular time period. We have various fee-based agreements with customers to transport their natural gas through our pipelines. Our customers retain ownership of their natural gas shipped through our pipelines. As such, our pipeline transportation activities are not intended to create physical volume differences that would result in significant accounting or economic events for either our customers or us during the course of the arrangement.

We settle pipeline gas imbalances through either (i) physical delivery of in-kind gas or (ii) in cash. These settlements follow contractual guidelines or common industry practices. As imbalances occur, they may be settled: (i) on a monthly basis; (ii) at the end of the agreement; or (iii) in accordance with industry practice, including negotiated settlements. Certain of our natural gas pipelines have a regulated tariff rate mechanism requiring customer imbalance settlements each month at current market prices.

However, the vast majority of our settlements are through in-kind arrangements whereby incremental volumes are delivered to or received from a customer. Such in-kind deliveries are ongoing and take place over several periods. In some cases, settlements of imbalances built up over a period of time are ultimately cashed out and are generally negotiated at values which approximate average market prices over a period of time. For those gas imbalances that are ultimately settled over future periods, we estimate the value of such current assets and liabilities using average market prices, which we believe is representative of the value of the imbalances upon final settlement. Changes in natural gas prices may impact our estimates.

The following table presents our natural gas imbalance receivables/payables at the dates indicated:

	December 31,	
	2009	2008
Natural gas imbalance receivables	$ 9.8	$ 35.7
Natural gas imbalance payables (1)	11.0	43.6

(1) Reflected as a component of “Accrued product payables” on our Consolidated Balance Sheets.

Property, Plant and Equipment

Property, plant and equipment is recorded at cost. Expenditures for additions, improvements and other enhancements to property, plant and equipment are capitalized. Minor replacements, maintenance, and repairs that do not extend asset life or add value are charged to expense as incurred. When property, plant and equipment assets are retired or otherwise disposed of, the related cost and accumulated depreciation are removed from the accounts and any resulting gain or loss is included in the results of operations for the respective period.

In general, depreciation is the systematic and rational allocation of an asset’s cost, less its residual value (if any), to the periods it benefits. The majority of our property, plant and equipment is depreciated using the straight-line method, which results in depreciation expense being incurred evenly over the life of the assets. Our estimate of depreciation incorporates assumptions regarding the useful economic lives and residual values of our assets. At the time we place our assets in service, we believe such assumptions are reasonable. Under our depreciation policy for midstream energy assets such as the Texas Intrastate System, the remaining economic lives of such assets are limited to the estimated life of the natural resource bas ins (based on proved reserves at the time of the analysis) from which such assets derive their throughput volumes. Our forecast of the remaining life for the applicable resource basins is based on several factors, including information published by the U.S. Energy Information Administration. Where appropriate, we use other depreciation methods (generally accelerated) for tax purposes.

Leasehold improvements are recorded as a component of property, plant and equipment. The cost of leasehold improvements is charged to earnings using the straight-line method over the shorter of the remaining lease term or the estimated useful lives of the improvements. We consider renewal terms that are deemed reasonably assured when estimating remaining lease terms.

Our assumptions regarding the useful economic lives and residual values of our assets may change in response to new facts and circumstances, which would change our depreciation amounts prospectively. Examples of such circumstances include, but are not limited to: (i) changes in laws and regulations that limit the estimated economic life of an asset; (ii) changes in technology that render an asset obsolete; (iii) changes in expected salvage values; or (iv) significant changes in the forecast life of proved reserves of applicable resource basins, if any.

Certain of our plant operations require periodic planned outages for major maintenance activities. These planned shutdowns typically result in significant expenditures, which are principally comprised of amounts paid to third parties for materials, contract services and related items. We use the expense-as-incurred method for any planned major maintenance activities.

Asset retirement obligations ("AROs") are legal obligations associated with the retirement of tangible long-lived assets that result from their acquisition, construction, development and/or normal operation. When an ARO is incurred, we record a liability for the ARO and capitalize an equal amount as an increase in the carrying value of the related long-lived asset. Over time, the liability is accreted to its present value (accretion expense) and the capitalized amount is depreciated over the remaining useful life of the related long-lived asset. We will incur a gain or loss to the extent that our ARO liabilities are not settled at their recorded amounts. See Note 8 for additional information regarding our property, plant and equipme nt.

Revenue Recognition

In general, we recognize revenue from our customers when all of the following criteria are met: (i) persuasive evidence of an exchange arrangement exists, (ii) delivery has occurred or services have been rendered, (iii) the buyer's price is fixed or determinable and (iv) collectibility is reasonably assured. See Note 4 for information regarding our revenue recognition policies.

Note 3. Recent Accounting Developments

The accounting standard setting bodies have recently issued the following guidance that will or may affect our future financial statements:

Fair Value Measurements. In January 2010, the FASB issued new guidance to improve disclosures about fair value measurements. This new guidance requires the following:

§ Effective with the first quarter of 2010, additional disclosures will be required regarding the reporting of transfers of fair value information between the three levels of the fair value hierarchy (i.e., Levels 1, 2 and 3).

§ Effective with the first quarter of 2011, companies will need to present purchases, sales, issuances and settlements whose fair values are based on unobservable inputs on a gross basis.

Other than requiring enhanced fair value disclosures, we do not expect our adoption of this guidance will have a material impact on our consolidated financial statements.

Consolidation of Variable Interest Entities. In June 2009, the FASB amended its consolidation guidance regarding variable interest entities. In general, this new guidance places more emphasis on a qualitative analysis, rather than a purely quantitative approach, in determining which company should consolidate a variable interest entity. Our adoption of this guidance on January 1, 2010 did not have any impact on our consolidated financial statements.

Note 4. Revenue Recognition

We recognize revenue using the following criteria: (i) persuasive evidence of an exchange arrangement exists; (ii) delivery has occurred or services have been rendered; (iii) the buyer's price is fixed or determinable; and (iv) collectibility is reasonably assured. The following information provides a general description of our revenue recognition policies by segment:

Natural Gas Pipelines & Services

Our Natural Gas Pipelines & Services include approximately 9,400 miles of onshore natural gas pipeline systems that provide for the gathering and transportation of natural gas in Louisiana and Texas. We lease natural gas storage facilities located in Texas and Louisiana. This segment also includes our natural gas marketing activities.

Our natural gas pipelines typically generate revenues from transportation agreements where shippers are billed a fee per unit of volume transported (typically per million British thermal units, or "MMBtus") multiplied by the volume gathered or delivered. The transportation fees charged under these arrangements are either contractual or regulated by governmental agencies, including the Texas Railroad Commission. Certain of our natural gas pipelines offer firm capacity reservation services whereby the shipper pays a contractually stated fee based on the level of throughput capacity reserved in our pipelines whether or not the shipper actually utilizes such capacity. In connection with our natural gas transportation services and marketing activities, intrastate natural gas pipelines (such as o ur Acadian Gas System) may also purchase natural gas from producers and other suppliers for transport and resale to customers such as electric utility companies, local natural gas distribution companies, industrial users and other natural gas marketing companies.

Revenues from natural gas storage contracts typically have two components: (i) monthly demand payments, which are associated with a customer's storage capacity reservations and paid regardless of actual usage and (ii) storage fees per unit of volume stored at our facilities. Revenues from demand payments are recognized during the period the customer reserves capacity. Revenues from storage fees are recognized in the period the services are provided.

Our natural gas marketing activities generate revenues from the sale and delivery of natural gas obtained from third-party well-head purchases, regional natural gas processing plants and the open market. Revenues from these sales contracts are recognized when the natural gas is delivered to customers. In general, sales prices referenced in these contracts are market-based and may include pricing differentials for such factors as delivery location.

NGL Pipelines & Services

Our NGL Pipelines & Services include our (i) NGL marketing activities related to our Big Thicket Gathering System; (ii) NGL pipelines aggregating 1,317 miles; (iii) NGL and related product storage facilities and (iv) NGL fractionation facilities.

The NGL marketing activities of our Big Thicket Gathering System generate revenues from the sale and delivery of NGLs obtained through natural gas processing agreements at EPO's Indian Springs natural gas processing plant located in east Texas. The results of operations from our NGL marketing activities are generally dependent upon the volume of products sold and the market-based sales prices charged to customers.

Under our NGL pipeline transportation contracts, revenue is recognized when volumes have been delivered to customers. Revenue from these contracts is generally based upon a fixed fee per gallon of liquids transported multiplied by the volume delivered. Transportation fees charged under these arrangements are contractual and not typically regulated by governmental agencies.

We collect storage revenues under our NGL and related product storage contracts based on the number of days a customer has volumes in storage multiplied by a storage rate (as defined in each contract). Under these contracts, revenue is recognized ratably over the length of the storage period. With respect to capacity reservation agreements, we collect a fee for reserving storage capacity for customers in our underground storage wells. Under these agreements, revenue is recognized ratably over the specified reservation period. Excess storage fees are collected when customers exceed their reservation amounts and are recognized in the period of occurrence. In addition, we derive brine production revenues from customers that use brine in the production of feedstocks for polyvinyl chloride.

We enter into fee-based arrangements for the NGL fractionation services we provide to customers. Under such fee-based arrangements, revenue is recognized in the period services are provided. Such fee-based arrangements typically include a base-processing fee (usually stated in cents per gallon) that is contractually subject to adjustment for changes in certain fractionation expenses (e.g. natural gas fuel costs).

Petrochemical Services

Our Petrochemical Services consists of our petrochemical pipelines aggregating 284 miles. Revenues recorded for the Lou-Tex Propylene Pipeline and Sabine Propylene Pipeline are primarily based on exchange agreements with Shell Oil Company and Exxon Mobil Corporation ("Exxon Mobil"). As a result of these exchange agreements, we agree to receive propylene in one location and deliver propylene at another location for a fee. Revenue from these contracts is generally based upon a fixed fee per unit of volume of liquids transported multiplied by the volume delivered and may include deficiency fee provisions if certain minimum delivery requirements are not met.

Note 5. Equity-based Awards

The following table summarizes the expense we recognized in connection with equity-based awards issued under EPCO's long-term incentive plans for the periods presented (which awards relate to units of affiliates other than Duncan Energy Partners L.P.):

	For Year Ended December 31,		
	2009	2008	2007
Restricted unit awards (1)	$ 1.4	$ 0.7	$ 0.3
Unit option awards (1)	0.2	--	--
Profits interests awards (1)	0.6	0.2	0.2
Total compensation expense	$ 2.2	$ 0.9	$ 0.5

(1) Accounted for as equity-classified awards. The fair value of an equity-classified award is amortized to earnings on a straight-line basis over the requisite service or vesting period.

An allocated portion of the non-cash amortization expense of these awards is charged to us under the administrative services agreement ("ASA") with EPCO. We recognize a non-cash expense for our allocated share of the amortized grant date fair value of such awards, with an offsetting amount recorded in equity. See Note 15 for a general description of the ASA with EPCO. With the exception of certain amounts recorded in connection with EPCO Unit, as defined later in this note, we are not responsible for reimbursing EPCO for any other expenses associated with such awards. Beginning in February 2009, the ASA was amended to provide that we and other affiliates of EPCO will reimburse EPCO for our allocated share of distributions of cash or securities made to the Class B limited partners of EPCO Unit. Our reimbursements to EPCO during 2009 in connection with EPCO Unit were $0.1 million.

We have been allocated expense amounts associated with the following long-term incentive plans of EPCO: (i) the Enterprise Products 1998 Long-Term Incentive Plan ("1998 Plan") and (ii) the Amended and Restated 2008 Enterprise Products Long-Term Incentive Plan ("2008 Plan").

The 1998 Plan provides for awards of Enterprise Products Partners' 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 units, phantom units, unit appreciation rights ("UARs") and distribution equivalent rights ("DERs"). Up to 7,000,000 of Enterprise Products Partners' common units may be issued as awards under the 1998 Plan. After giving effect to awards granted under the plan through December 31, 2009, a total of 652,543 additional common units of Enterprise Products Partners could be issued. All of the awards issued for which we have been allocated expen se were in the form of unit options and restricted units.

The 2008 Plan provides for awards of Enterprise Products Partners' 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 units, phantom units, UARs and DERs. Up to 10,000,000 of Enterprise Products Partners' common units may be issued as awards under the 2008 Plan. After giving effect to awards granted under the plan through December 31, 2009, a total of 7,865,000 additional common units of Enterprise Products Partners could be issued. All of the awards issued for which we have been allocated expense were in the form of unit options.

DEP Unit Purchase Plan ("EUPP") and
2010 Duncan Energy Partners L.P. Long-Term Incentive Plan ("2010 Plan")

On December 10, 2009, the board of directors of our general partner (the "Board") unanimously approved a resolution adopting both the 2010 Plan and the EUPP. The 2010 Plan provides for awards of options to purchase common units, restricted common units, UARs, phantom units and DERs to employees, directors or consultants providing services to us and our subsidiaries. The EUPP provides eligible employees the opportunity to purchase common units at a discount through withholdings from eligible compensation. On December 30, 2009, the action taken by the Board regarding the plans was approved by written consent of a subsidiary of EPO, which held of record approximately 58.6% of our outstanding common units as of that date. Beca use EPO's subsidiary held a majority of our common units as of December 30, 2009, no other votes were necessary to adopt the plans. In February 2010, we filed a registration statement with the SEC authorizing the issuance of up to 500,000 common units in connection with the 2010 Plan and 500,000 common units in connection with the EUPP. The plans became effective on February 11, 2010.

Summary of EPCO long-term incentive plans

The following information is being provided regarding EPCO's long-term incentive plans under which we have or may receive an allocation of expense. In addition to the 1998 Plan and 2008 Plan, EPCO's active long-term incentive plans include the Enterprise Products 2006 TPP Long-Term Incentive Plan ("2006 Plan"), under which unit options, restricted units and other awards may be issued. EPCO also has other plans under which liability-classified awards may be issued. As of December 31, 2009, we have not been allocated any costs of liability-classified awards and therefore have not included any discussion of such plans in these disclosures. EPCO may create additional long-term incentive plans in the future that may result in us receiving an allocation of expense based on services rendered to us by the recipients of such awards. Unless noted otherwise, the following information is presented on a gross basis (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 Unit Awards

Restricted unit awards allow recipients to acquire common units of Enterprise Products Partners (at no cost to the recipient) once a defined vesting period expires, subject to customary forfeiture provisions. The restrictions on such awards generally lapse four years from the date of grant. The fair value of restricted units 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. As used in the context of Enterprise Products Partners' long-term incentive plans, the term "restricted unit" represents a time-vested unit. Such awards are non-vested until the required servic e period expires.

The following table summarizes information regarding Enterprise Products Partners' restricted unit awards for the periods indicated:

	Number of Units	Weighted-Average Grant Date Fair Value per Unit (1)
Restricted units at December 31, 2006	1,105,237	$ 24.79
Granted (2)	738,040	$ 30.64
Vested	(4,884)	$ 25.28
Settled or forfeited (3)	(149,853)	$ 23.31
Restricted units at December 31, 2007	1,688,540	$ 27.23
Granted (4)	766,200	$ 30.73
Vested	(285,363)	$ 23.11
Forfeited	(88,777)	$ 26.98
Restricted units at December 31, 2008	2,080,600	$ 29.09
Granted (5)	1,025,650	$ 24.89
Vested	(281,500)	$ 26.70
Forfeited	(411,884)	$ 28.37
Awards assumed in connection with TEPPCO Merger	308,016	$ 27.64
Restricted units at December 31, 2009	2,720,882	$ 27.70

(1) Determined by dividing the aggregate grant date fair value of awards before an allowance for forfeitures by the number of awards issued. With respect to restricted unit awards assumed in connection with the TEPPCO Merger, the weighted-average grant date fair value per unit was determined by dividing the aggregate grant date fair value of the assumed awards before an allowance for forfeitures by the number of awards assumed.

(2) Aggregate grant date fair value of restricted unit awards issued during 2007 was $22.6 million based on grant date market prices of Enterprise Products Partners' common units ranging from $28.00 to $31.83 per unit. Estimated forfeiture rates ranging between 4.6% and 17% were applied to these awards.

(3) Reflects the settlement of 113,053 restricted units in connection with the resignation of EPGP's former chief executive officer.

(4) Aggregate grant date fair value of restricted unit awards issued during 2008 was $23.5 million based on grant date market prices of Enterprise Products Partners' common units ranging from $25.00 to $32.31 per unit. An estimated forfeiture rate of 17% was applied to these awards.

(5) Aggregate grant date fair value of restricted unit awards issued during 2009 was $25.5 million based on grant date market prices of Enterprise Products Partners' common units ranging from $20.08 to $28.73 per unit. Estimated forfeiture rates ranging between 4.6% and 17% were applied to these awards.

On a gross basis, the total unrecognized compensation cost of such awards was $37.9 million at December 31, 2009, of which our share is currently estimated to be $4.0 million. We expect to recognize our share of the unrecognized compensation cost for these awards over a weighted-average period of 2.3 years.

Unit Option Awards

Certain of Enterprise Products Partners' long-term incentive plans provide for the issuance of non-qualified incentive options to purchase a fixed number of its common units. When issued, the exercise price of each option grant may be no less than the market price of the underlying security on the date of grant. In general, options granted under the EPCO plans have a vesting period of four years and remain exercisable for five to ten years, as applicable, from the date of grant.

The fair value of each unit option is estimated on the date of grant using the Black-Scholes option pricing model, which incorporates various assumptions including expected life of the options, risk-free interest rates, expected distribution yield on Enterprise Products Partners' common units, and expected unit price volatility of its common units. In general, the assumption of expected life of the options represents the period of time that the options are expected to be outstanding based on an analysis of historical option activity. The selection of the risk-free interest rate is based on published yields for U.S. government securities with comparable terms. The expected distribution yield and unit price volatility is estimated based on several fac tors, which include an analysis of Enterprise Products Partners' historical unit price volatility and distribution yield over a period equal to the expected life of the option.

During 2008, in response to changes in the federal tax code applicable to certain types of equity awards, Enterprise Products Partners amended the terms of certain of its outstanding unit options. In general, the expiration dates of these awards were modified from May and August 2017 to December 2012.

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 Products Partners.

The following table presents unit option activity under the EPCO plans for the periods indicated:

	Number of Units	Weighted-Average Strike Price (dollars/unit)	Weighted-Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value (1)
Outstanding at December 31, 2006	2,416,000	$ 23.32		
Granted (2)	895,000	30.63		
Exercised	(256,000)	19.26		
Settled or forfeited (3)	(740,000)	24.62		
Outstanding at December 31, 2007	2,315,000	26.18		
Granted (4)	795,000	30.93		
Exercised	(61,500)	20.38		
Forfeited	(85,000)	26.72		
Outstanding at December 31, 2008	2,963,500	27.56		
Granted (5)	1,460,000	23.46		
Exercised	(261,000)	19.61		
Forfeited	(930,540)	26.69		
Awards assumed in connection with TEPPCO Merger	593,960	26.12		
Outstanding at December 31, 2009 (6)	3,825,920	26.52	4.6	$ 2.8
Options exercisable at:				
December 31, 2007	335,000	$ 22.06	4.0	$ 3.3
December 31, 2008	548,500	$ 21.47	4.1	$ --
December 31, 2009 (6)	447,500	$ 25.09	4.8	$ 2.8

(1) Aggregate intrinsic value reflects fully vested unit options at the date indicated.
(2) Aggregate grant date fair value of these unit options issued during 2007 was $2.4 million based on the following assumptions: (i) a weighted-average grant date market price of Enterprise Products Partners' common units of $30.63 per unit; (ii) expected life of options of 7.0 years; (iii) weighted-average risk-free interest rate of 4.8%; (iv) weighted-average expected distribution yield on Enterprise Products Partners' common units of 8.4%; and (v) weighted-average expected unit price volatility on Enterprise Products Partners' common units of 23.2%.
(3) Includes the settlement of 710,000 options in connection with the resignation of EPGP's chief executive officer.
(4) Aggregate grant date fair value of these unit options issued during 2008 was $1.9 million based on the following assumptions: (i) a grant date market price of Enterprise Products Partners' common units of $30.93 per unit; (ii) expected life of options of 4.7 years; (iii) a risk-free interest rate of 3.3%; (iv) an expected distribution yield on Enterprise Products Partners' common units of 7.0%; and (v) an expected unit price volatility on Enterprise Products Partners' common units of 19.8%. An estimated forfeiture rate of 17.0% was applied to awards granted during 2008.
(5) Aggregate grant date fair value of these unit options issued during 2009 was $8.1 million based on the following assumptions: (i) a weighted-average grant date market price of Enterprise Products Partners' common units of $23.46 per unit; (ii) weighted-average expected life of options of 4.8 years; (iii) weighted-average risk-free interest rate of 2.1%; (iv) weighted-average expected distribution yield on Enterprise Products Partners' common units of 9.4%; and (v) weighted-average expected unit price volatility on Enterprise Products Partners' common units of 57.4%. An estimated forfeiture rate of 17.0% was applied to awards granted during 2009.
(6) Enterprise Products Partners was committed to issue 3,825,920 and 2,963,500 of Enterprise Products Partners' common units at December 31, 2009 and 2008, respectively, if all outstanding options awarded (as of these dates) were exercised. Of the option awards outstanding at December 31, 2009, an additional 410,000, 712,280, 736,000 and 1,520,140 are exercisable in 2010, 2012, 2013 and 2014, respectively.

On a gross basis, the total unrecognized compensation cost of such awards was $7.3 million at December 31, 2009, of which our share is currently estimated to be $0.6 million. We expect to recognize our share of the unrecognized compensation cost for these awards over a weighted-average period of 2.9 years.

Profits Interests Awards

As long-term incentive arrangements, EPCO has granted its key employees who perform services on behalf of us, EPCO and other affiliated companies, "profits interests" in several limited partnerships (the "Employee Partnerships"), all of which are privately held affiliates of EPCO. Profits interests awards entitle each holder to participate in the expected long-term appreciation in value of the equity securities owned by each Employee Partnership. The Employee Partnerships in which our named executive officers participate own either units of Enterprise GP Holdings or Enterprise Products Partners or a combination of both. The profits interests awards are subject to customary forfeiture provisions.

Each Employee Partnership has a single Class A limited partner, which is a privately held indirect subsidiary of EPCO, and a varying number of Class B limited partners. At formation, the Class A limited partner either contributes cash or limited partner units it owns to the Employee Partnership. If cash is contributed, the Employee Partnership uses these funds to acquire limited partner units on the open market. In general, the Class A limited partner earns a preferred return (either fixed or variable depending on the partnership agreement) on its investment (or "Capital Base") in the Employee Partnership and residual quarterly cash amounts, if any, are distributed to the Class B limited partners. Upon liquidation, Employee Partners hip assets having a fair market value equal to the Class A limited partner's Capital Base, plus any preferred return for the period in which liquidation occurs, will be distributed to the Class A limited partner. Any remaining assets will be distributed to the Class B limited partner(s) as a residual profits interest and are a factor of the appreciation in value of the partnership's assets since its formation date.

The grant date fair value of each Employee Partnership is based on (i) the estimated value of the remaining assets, as determined using a Black-Scholes option pricing model, that would be distributed to the Class B limited partners upon dissolution of the Employee Partnership and (ii) the value, based on a discounted cash flow analysis using appropriate discount rates, of the residual quarterly cash amounts that the Class B limited partners are expected to receive over the life of the Employee Partnership.

The following table summarizes key elements of each Employee Partnership as of December 31, 2009. As used in the table in reference to the description of assets, "EPE" means Enterprise GP Holdings L.P. and "EPD" means Enterprise Products Partners L.P.

Employee Partnership	**Description of Assets**	**Initial Class A Capital Base**	**Class A Partner Preferred Return**	**Liquidation Date** (1)	**Grant Date Fair Value of Awards**	**Unrecognized Compensation Cost**
EPE Unit I	1,821,428 EPE units	$51.0 million	4.50% to 5.725%	February 2016	$21.5 million	$12.1 million
EPE Unit II	40,725 EPE units	$1.5 million	4.50% to 5.725%	February 2016	$0.4 million	$0.3 million
EPE Unit III	4,421,326 EPE units	$170.0 million	3.80%	February 2016	$42.8 million	$30.8 million
Enterprise Unit	881,836 EPE units 844,552 EPD units	$51.5 million	5.00%	February 2016	$6.5 million	$5.3 million
EPCO Unit	779,102 EPD units	$17.0 million	4.87%	February 2016	$8.1 million	$6.5 million

(1) The liquidation date may be accelerated for change of control and other events as described in the underlying partnership agreements.

The total unrecognized compensation cost of the profits interests awards was $55.0 million at December 31, 2009 of which our share is currently estimated to be $3.8 million. We expect to recognize our share of the unrecognized compensation cost for these awards over a weighted-average period of 6.1 years.

In December 2009, the expected liquidation date for each Employee Partnership was extended to February 2016. This modification follows a similar set of modifications made in July 2008 for EPE Unit I, EPE Unit II and EPE Unit III that extended liquidation dates as well as reduced the Class A limited partner's preferred return rates. These modifications are intended to align the interests of the employee partners of the Employee Partnerships with the long-term interests of EPCO and other unitholders in the relevant underlying publicly traded partnerships, which also hold indirectly a significant ownership interest in both us and our subsidiaries.

The following table presents the impact of modifications (e.g., extension of liquidation dates) and other changes on the aggregate grant date fair value (on an unallocated basis) of the Employee Partnerships for the periods presented.

	For Year Ended December 31,		
	2009	2008	2007
Aggregate grant date fair values at beginning of period	$ 64.6	$ 35.4	$ 12.8
New Employee Partnership grants (1,2)	--	14.6	23.0
Award modifications	19.5	15.0	--
Other adjustments, primarily forfeiture and regrant activity (2)	(4.8)	(0.4)	(0.4)
Aggregate grant date fair value at end of period	$ 79.3	$ 64.6	$ 35.4

(1) EPE Unit III was formed in 2007 and EPCO Unit and Enterprise Unit were formed in 2008.
(2) TEPPCO Unit L.P. and TEPPCO Unit II L.P. were formed during 2008 and dissolved during 2009.

The following table summarizes the assumptions used in deriving that portion of the estimated grant date fair value for each Employee Partnership using a Black-Scholes option pricing model:

Employee Partnership	Expected Life of Award	Risk-Free Interest Rate	Expected Distribution Yield	Expected Unit Price Volatility
EPE Unit I	3 to 6 years	1.2% to 5.0%	3.0% to 6.7%	16.6% to 35.0%
EPE Unit II	4 to 6 years	1.6% to 4.4%	3.8% to 6.4%	18.7% to 31.7%
EPE Unit III	4 to 6 years	1.4% to 4.9%	4.0% to 6.4%	16.6% to 32.2%
Enterprise Unit	4 to 6 years	1.4% to 3.9%	4.5% to 8.4%	15.3% to 31.7%
EPCO Unit	4 to 6 years	1.6% to 2.4%	8.1% to 11.1%	27.0% to 50.0%

Note 6. Derivative Instruments, Hedging Activities and Fair Value Measurements

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

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

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

§ Variable cash flows of a forecasted transaction - In a cash flow hedge, the effective portion of the hedge is reported in other comprehensive income ("OCI") 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 changes in the 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 i n 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.

Interest Rate Derivative Instruments

We utilize interest rate swaps to manage our exposure to changes in the interest rates of certain consolidated debt agreements. This strategy is a component in controlling our cost of capital associated with such borrowings.

The following table summarizes our interest rate derivative instruments outstanding at December 31, 2009, all of which were designated as hedging instruments under the FASB's derivative and hedging guidance:

Hedged Variable Rate Debt	Number of Swaps	Period Covered by Swap	Termination Date of Swap	Variable to Fixed Rate (1)	Notional Value
Revolving Credit Facility, due Feb. 2011	3	Sep. 2007 to Sep. 2010	Sep. 2010	0.25% to 4.62%	$175.0 million

(1) Amounts receivable from or payable to the swap counterparties are settled every three months.

Cash flow hedges fix the interest rate paid on floating rate debt with the difference between the floating rate and fixed rate being recorded as an increase/decrease to interest expense. This combined activity resulted in an increase of interest expense of $6.5 million and $2.0 million, respectively, for 2009 and 2008.

For information regarding consolidated fair value amounts and gains and losses on interest rate derivative instruments and related hedged items, see "Tabular Presentation of Fair Value Amounts, and Gains and Losses on Derivative Instruments and Related Hedged Items" within this Note 6.

Commodity Derivative Instruments

The price of natural gas is subject to fluctuations in response to changes in supply and demand, market conditions and a variety of additional factors that are beyond our control. In order to manage the price risk associated with certain exposures, we enter into commodity derivative instruments such as forwards, basis swaps and futures contracts. The following table summarizes the absolute notional amount of our commodity derivative instruments outstanding at December 31, 2009:

	Volume		Accounting
Derivative Purpose	Current	Long-Term	Treatment
Derivatives not designated as hedging instruments:			
Acadian Gas:			
Natural gas risk management activities	2.2 Bcf	n/a	Mark-to-market

At December 31, 2009, none of our derivative instruments met hedge accounting requirements; therefore, they are accounted for using mark-to-market accounting.

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 the purchase of natural gas held-for-sale to third parties.

Historically, the use of commodity derivative instruments was governed by policies established by the general partner of Enterprise Products Partners. Our general partner now 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.

For information regarding consolidated fair value amounts and gains and losses on commodity derivative instruments and related hedged items, see "Tabular Presentation of Fair Value Amounts, and Gains and Losses on Derivative Instruments and Related Hedged Items" within this Note 6.

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 December 31, 2009, we did not have any derivative instruments in a net liability position. The potential for derivatives with contingent features to enter a net liability position may change in the future as 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			
	December 31, 2009		December 31, 2008		December 31, 2009		December 31, 2008	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
<u>Derivatives designated as hedging instruments:</u>								
Interest rate derivatives	Other current assets	$ --	Other current assets	$ --	Other current liabilities	$ 5.5	Other current liabilities	$ 5.9
Interest rate derivatives	Other assets	--	Other assets	--	Other liabilities	--	Other liabilities	3.9
Total derivatives designated as hedging instruments		$ --		$ --		$ 5.5		$ 9.8
<u>Derivatives not designated as hedging instruments:</u>								
Commodity derivatives	Other current assets	$ 0.1	Other current assets	$ 1.9	Other current liabilities	$ 0.1	Other current liabilities	$ 2.0
Total derivatives not designated as hedging instruments		$ 0.1		$ 1.9		$ 0.1		$ 2.0

The following tables present the effect of our derivative instruments designated as cash flow hedges on our Statements of Consolidated Operations for the periods presented:

Derivatives in Cash Flow Hedging Relationships	Change in Value Recognized in OCI on Derivative (Effective Portion) For the Twelve Months Ended December 31, 2009	2008
Interest rate	$ (2.5)	$ (8.0)
Commodity	--	(0.7)
Total	$ (2.5)	$ (8.7)

Derivatives in Cash Flow Hedging Relationships	Location of Loss Reclassified from AOCI into Income (Effective Portion)	Amount of Loss Reclassified from AOCI into Income (Effective Portion) For the Twelve Months Ended December 31, 2009	2008
Interest rate	Interest expense	$ (6.6)	$ (2.0)
Commodity	Revenue	--	(0.7)
Total		$ (6.6)	$ (2.7)

Derivatives in Cash Flow Hedging Relationships	Location	Amount of Gain Recognized in Income on Ineffective Portion of Derivative For the Twelve Months Ended December 31, 2009	2008
Interest rate derivatives	Interest expense	$ 0.1	$ *
Total		$ 0.1	$ *

* Indicates that amounts are negligible and less than $0.1 million.

Over the next twelve months, we expect to reclassify $5.4 million of AOCI attributable to interest rate derivative instruments into earnings as an increase to interest expense, based on the current level of interest rates.

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

Derivatives Not Designated as Hedging Instruments	Location	Gain/(Loss) Recognized in Income on Derivative Amount For the Twelve Months Ended December 31, 2009	2008
Commodity derivatives	Revenue	$ (0.6)	$ 0.7
Total		$ (0.6)	$ 0.7

Fair Value Measurements

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

A three-tier hierarchy has been established that classifies fair value amounts recognized or disclosed in the financial statements based on the observability of inputs used to estimate such fair values. The hierarchy considers fair value amounts based on observable inputs (Levels 1 and 2) to be more reliable and predictable than those based primarily on unobservable inputs (Level 3). At each balance sheet reporting date, we categorize our financial assets and liabilities using this hierarchy. The characteristics of fair value amounts classified within each level of the hierarchy are described as follows:

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

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

§ Level 3 fair values are based on unobservable inputs. Unobservable inputs are used to measure fair value to the extent that observable inputs are not available, thereby allowing for situations in which there is little, if any, market activity for the asset or liability at the measurement date. Unobservable inputs reflect the reporting entity's own ideas about the assumptions that market participants would use in pricing an asset or liability (including assumptions about risk). Unobservable inputs are based on the best information available in the circumstances, which might include the reporting entity's internally developed data. The reporting entity must not ignore information about market participant assumptions that is reasonably available without undue cost and effort. Level 3 inpu ts are typically used in connection with internally developed valuation methodologies where management makes its best estimate of an instrument's fair value. Level 3 generally includes specialized or unique financial instruments that are tailored to meet a customer's specific needs. At December 31, 2009, we did not have any Level 3 financial assets or liabilities.

The following tables set forth, by level within the fair value hierarchy, our financial assets and liabilities measured on a recurring basis at the dates indicated. These financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of the fair value assets and liabilities, in addition to their placement within the fair value hierarchy levels.

	At December 31, 2009		
	Level 1	Level 2	Total
Financial assets:			
Commodity derivative instruments	$ 0.1	$ *	$ 0.1
Financial liabilities:			
Commodity derivative instruments	$ *	$ 0.1	$ 0.1
Interest rate derivative instruments	--	5.5	5.5
Total derivative liabilities	$ *	$ 5.6	$ 5.6

* Indicates that amounts are negligible and less than $0.1 million.

	At December 31, 2008		
	Level 1	Level 2	Total
Financial assets:			
Commodity derivative instruments	$ *	$ 1.9	$ 1.9
Financial liabilities:			
Commodity derivative instruments	$ 1.9	$ 0.1	$ 2.0
Interest rate derivative instruments	--	9.8	9.8
Total derivative liabilities	$ 1.9	$ 9.9	$ 11.8

* Indicates that amounts are negligible and less than $0.1 million.

Nonfinancial Assets and Liabilities

Certain nonfinancial assets and liabilities are measured at fair value on a nonrecurring basis and are subject to fair value adjustments in certain circumstances (e.g., when there is evidence of impairment). The following table presents the estimated fair value of certain assets carried on our Consolidated Balance Sheet by caption for which a nonrecurring change in fair value has been recorded during the year ended December 31, 2009:

	Level 3	Impairment Charges
Property, plant and equipment	$ 1.8	$ 4.2

Using appropriate valuation techniques, we adjusted the carrying value of certain of our Natural Gas Pipelines and Services segment assets when we recorded a non-cash asset impairment charge of $3.3 million due to the cancellation of a compressor station project on our Texas Intrastate System. We also adjusted the carrying value of certain pipeline segments of the Texas Intrastate System to fair value during 2009. Anticipated abandonment activities related to a portion of this system led to a non-cash impairment charge of $0.9 million. These impairment charges are reflected in operating costs and expenses for the year ended December 31, 2009.

Note 7. Inventories

Our inventory amounts were as follows at the dates indicated:

	December 31, 2009	December 31, 2008
Working inventory (1)	$ 4.4	$ 18.3
Forward sales inventory (2)	6.1	9.7
Total inventory	$ 10.5	$ 28.0

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

Working inventory includes natural gas volumes held for operational system balancing on the Texas Intrastate System. These natural gas inventories fluctuate as a result of imbalances with shippers and are valued based on a twelve-month rolling average of posted industry prices. When such volumes are delivered out of inventory, the average cost of these volumes is charged against our accrued gas imbalance payables. At December 31, 2009 and 2008, the value of natural gas held in inventory for operational system balancing was $2.8 million and $15.5 million, respectively.

As a result of fluctuating market conditions, we occasionally recognize LCM adjustments when the historical cost of our forward sales inventory exceeds its net realizable value. These non-cash adjustments are recorded as a component of cost of sales in the period they are recognized and generally affect our segment operating results in the following manner:

§ Write-downs of natural gas inventories are recorded as an expense related to our natural gas pipeline operations within our Natural Gas Pipelines & Services business segment.

To the extent our commodity hedging strategies address inventory-related risks and are successful, these inventory valuation adjustments are mitigated or offset. See Note 6 for a description of our commodity hedging activities.

The following table summarizes our cost of sales and LCM adjustments for the periods indicated:

	For Year Ended December 31,		
	2009	2008	2007
Cost of sales (1)	$ 490.0	$ 1,122.4	$ 811.4
LCM adjustments	*	1.8	0.3

(1) Cost of sales is included in operating costs and expenses, as presented on our Statements of Consolidated Operations. The fluctuation in this amount year-to-year is primarily due to changes in natural gas prices.
* We recognized nominal LCM adjustments for the year ended December 31, 2009.

Note 8. Property, Plant and Equipment

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

	Estimated Useful Life in Years	At December 31, 2009	At December 31, 2008
Plant and pipeline facilities (1)	3-45(4)	$ 4,767.0	$ 4,175.0
Underground storage wells and related assets (2)	5-35(5)	432.5	407.9
Transportation equipment (3)	3-10	11.3	10.3
Land		27.8	23.9
Construction in progress		233.6	459.0
Total		5,472.2	5,076.1
Less accumulated depreciation		922.6	745.9
Property, plant and equipment, net		$ 4,549.6	$ 4,330.2

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

We reviewed assumptions underlying the estimated remaining useful lives of certain of our assets during the first quarter of 2008. As a result of our review, we increased the remaining useful lives of certain assets, most notably the assets that constitute our Texas Intrastate System as of January 1, 2008.

These revisions extended the remaining useful life of such assets to incorporate recent data showing that proved natural gas reserves supporting volumes for these assets have increased their estimated useful life. There were no changes to the residual values of these assets. These revisions prospectively reduced our depreciation expense on assets having carrying values totaling $2.72 billion at January 1, 2008. As a result of this change in estimate, depreciation expense decreased by approximately $20.0 million for the year ended December 31, 2008. The reduction in depreciation expense increased operating income and net income by equal amounts from what they would have been absent the change. Depreciation expense for the years ended December 31, 2009, 2008 and 2007 was $1 76.7 million, $158.5 million and $163.4 million, respectively.

Asset Retirement Obligations

We have recorded conditional AROs in connection with certain right-of-way agreements, leases and regulatory requirements. Conditional AROs are obligations in which the timing and/or amount of settlement are uncertain. None of our assets are legally restricted for purposes of settling AROs.

The following table presents information regarding our AROs since December 31, 2007.

ARO liability balance, December 31, 2007	$	8.1
Liabilities incurred		1.3
Liabilities settled		(5.3)
Accretion expense		0.3
Revisions in estimated cash flows		0.2
ARO liability balance, December 31, 2008	$	4.6
Liabilities settled		(0.7)
Accretion expense		0.6
Revisions in estimated cash flows		5.9
ARO liability balance, December 31, 2009	$	10.4

The increase in our ARO liability balance during 2009 primarily reflects revised estimates of the cost to comply with regulatory abandonment obligations associated with our TPC Offshore gathering system, a component of the Texas Intrastate System located offshore in the Gulf of Mexico. Net property, plant and equipment at December 31, 2009 and 2008 includes $5.5 million and $1.1 million, respectively, of asset retirement costs capitalized as an increase in the associated long-lived asset.

The following table presents forecasted accretion expense associated with our ARO's for the years presented:

2010	2011	2012	2013	2014
$ 0.7	$ 0.6	$ 0.6	$ 0.7	$ 0.8

Note 9. Investment in Evangeline

Acadian Gas, through a wholly owned subsidiary, owns a collective 49.51% equity interest in Evangeline, which consists of a 45% direct ownership interest in EGP and a 45.05% direct interest in EGC. EGC also owns a 10% direct interest in EGP. Third parties own the remaining equity interests in EGP and EGC. Acadian Gas does not have a controlling interest in the Evangeline entities, but does exercise significant influence on Evangeline's operating policies. Acadian Gas accounts for its financial 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 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 begins the earlier of July 1, 2010 or upon the payment in full of Evangeline's Series B notes and terminates on December 31, 2012. We cannot ascertain when, or if, Entergy will exercise this purchase option. 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 have received no distributions from Evangeline since we acquired our interest in Evangeline in April 2001. The trust indenture governing Evangeline's Series B notes places restrictions on the payment of distributions to Evangeline's partners. Evangeline is permitted to pay distributions if, after giving effect to the distribution, no default or event of default has occurred and is continuing, funds held in its restricted cash account equals or exceeds its debt service requirement and the holders of the Series B notes are cash secured. Our share of undistributed earnings of Evangeline totaled approximately $3.6 million at December 31, 2009. See Note 11 for a description of Evangeline's outstanding debt obligations.

Summarized financial information of Evangeline is presented below.

	At December 31,	
	2009	2008
BALANCE SHEET DATA:		
Current assets	$ 24.4	$ 33.5
Property, plant and equipment, net	3.2	4.2
Other assets	13.5	17.5
Total assets	$ 41.1	$ 55.2
Current liabilities	$ 10.6	$ 24.2
Other liabilities	17.7	20.4
Consolidated equity	12.8	10.6
Total liabilities and consolidated equity	$ 41.1	$ 55.2

	For the Year Ended December 31,		
	2009	2008	2007
INCOME STATEMENT DATA:			
Revenues	$ 164.5	$ 371.8	$ 272.9
Operating income	3.7	7.2	6.3
Net income	2.2	1.8	0.4

Note 10. Intangible Assets and Goodwill

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

	At December 31, 2009			At December 31, 2008		
	Gross Value	Accum. Amort.	Carrying Value	Gross Value	Accum. Amort.	Carrying Value
NGL Pipelines & Services:						
Customer relationship intangibles	$ 24.6	$ (8.9)	$ 15.7	$ 24.6	$ (6.4)	$ 18.2
Contract based intangibles	40.8	(24.7)	16.1	40.8	(20.1)	20.7
Natural Gas Pipelines & Services:						
Customer relationship intangibles	21.0	(9.0)	12.0	21.0	(7.6)	13.4
Total all segments	$ 86.4	$ (42.6)	$ 43.8	$ 86.4	$ (34.1)	$ 52.3

Due to the renewable nature of the underlying contracts, we amortize the Mont Belvieu storage contracts on a straight-line basis over the estimated 27 years of remaining economic life of the storage assets to which they relate. The value assigned to the Markham NGL storage contracts is being amortized to earnings over its estimated 2.3 years of remaining economic life, using the straight-line method. The Mont Belvieu and Markham NGL storage contracts are included in our NGL Pipelines & Services segment.

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.

The following table presents amortization expense attributable to our intangible assets (by segment) for the periods indicated:

	For the Year Ended December 31,		
	2009	2008	2007
NGL Pipelines & Services	$ 7.1	$ 7.6	$ 5.5
Natural Gas Pipelines & Services	1.4	1.5	1.7
Total segments	$ 8.5	$ 9.1	$ 7.2

Based on information currently available, the following table presents an estimate of future amortization expense associated with our intangible assets at December 31, 2009:

	For the Year Ended December 31,				
	2010	2011	2012	2013	2014
NGL Pipelines & Services	$ 6.7	$ 6.4	$ 2.9	$ 1.7	$ 1.5
Natural Gas Pipelines & Services	1.3	1.2	1.1	1.0	0.9
Total segments	$ 8.0	$ 7.6	$ 4.0	$ 2.7	$ 2.4

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. Our goodwill at December 31, 2009 and 2008 was $4.9 million and represents an allocation to the DEP II Midstream Businesses of the goodwill recorded by Enterprise Products Partners in connection with its merger with a third-party partnership in September 2004. The carrying value of our goodwill does not reflect any accumulated impairment charges.

Note 11. Debt Obligations

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

	At December 31,	
	2009	2008
Revolving Credit Facility, variable rate, due February 2011	$ 175.0	$ 202.0
Term Loan Agreement, variable rate, due December 2011	282.3	282.3
Total principal amount of long-term debt obligations	$ 457.3	$ 484.3

Revolving Credit Facility

We have, in place, a $300.0 million Revolving Credit Facility, all of which may be used for letters of credit, with a $30.0 million sublimit for Swingline Loans. Letters of credit outstanding under this facility reduce the amount available for borrowings. We may make up to two requests for one-year extensions of the maturity date (subject to certain restrictions).

At the closing of our initial public offering, we made an initial draw of $200.0 million under this facility to fund the $198.9 million cash distribution to EPO in connection with the DEP I drop down transaction (see Note 1) and the remainder to pay debt issuance costs. At December 31, 2009, the principal balance outstanding under this facility was $175.0 million. After taking into account amounts outstanding and the effect of the bankruptcy of one of the lenders, at December 31, 2009, we had the ability to borrow up to $121.7 million under our Revolving Credit Facility. We have hedged a significant portion of our variable interest rate exposure under this loan agreement; however, these hedges expire in September 2010. See Note 6 for informatio n regarding our interest rate hedging activities.

We can increase the borrowing capacity under our Revolving Credit Facility, without consent of the lenders, by an amount not to exceed $150.0 million, by adding to the facility one or more new lenders and/or requesting that the commitments of existing lenders be increased.

As defined in the credit agreement, variable interest rates charged under this facility may bear interest at either, (i) a Eurodollar rate plus an applicable margin or (ii) a Base Rate. The Base Rate is the higher of (i) the rate of interest publicly announced by the administrative agent, Wachovia Bank, National Association, as its Base Rate or (ii) 0.5% per annum above the Federal Funds Rate in effect on such date.

The credit facility contains certain financial and other customary affirmative and negative covenants. Also, if an event of default exists under the credit agreement, the lenders will be able to accelerate the maturity date of amounts borrowed under the credit agreement and exercise other rights and remedies.

Term Loan Agreement

In April 2008, we entered into a standby term loan agreement consisting of commitments for up to $300.0 million under the Term Loan Agreement. Subsequently, commitments under the Term Loan Agreement decreased to $282.3 million due to bankruptcy of one of the lenders. On December 8, 2008, we borrowed the full amount available under this loan agreement to fund the cash consideration due EPO in connection with the DEP II drop down transaction (see Note 1).

We may prepay loans under the Term Loan Agreement at any time, subject to prior notice in accordance with the credit agreement. Loans may also be payable earlier in connection with an event of default.

Loans under the Term Loan Agreement bear interest of the type specified in the applicable borrowing request, and consist of either Alternate Base Rate loans or Eurodollar loans. The Term Loan Agreement contains certain financial and other customary affirmative and negative covenants. Also, if an event of default exists under the credit agreement, the lenders will be able to accelerate the maturity date of amounts borrowed under the credit agreement and exercise other rights and remedies.

Covenants

We were in compliance with the covenants of our debt agreements at December 31, 2009.

Information Regarding Variable Interest Rates Paid

The following table presents the weighted-average interest rate paid on our consolidated variable-rate debt obligations during the year ended December 31, 2009.

	Weighted-average interest rate paid
Revolving Credit Facility, variable rate, due February 2011	1.4754%
Term Loan Agreement, variable rate, due December 2011	1.1486%

Evangeline Joint Venture Debt Obligation

The following table presents the debt obligations of Evangeline at the dates indicated:

	At December 31, 2009	At December 31, 2008
9.9% fixed interest rate senior secured notes due December 2010 ("Series B" notes):		
Current portion of debt – due December 31, 2010	$ 3.2	$ 5.0
Long-term portion of debt	--	3.2
$7.5 million subordinated note payable to an affiliate of other co-venture participant ("LL&E Note")	7.5	7.5
Total joint venture debt principal obligation	$ 10.7	$ 15.7

The Series B notes are collateralized by Evangeline's: (i) property, plant and equipment; (ii) proceeds from its Entergy natural gas sales contract (see Note 9); and (iii) a debt service reserve requirement. Scheduled principal repayments on the Series B notes are $5.0 million annually through December 2009, with a final repayment in 2010 of approximately $3.2 million. The trust indenture governing the Series B notes contains certain financial and other customary affirmative and negative covenants such as the maintenance of certain financial ratios. Evangeline was in compliance with such covenants during the year ended December 31, 2009.

The LL&E Note is subject to a subordination agreement which prevents the repayment of principal and accrued interest on the note until such time as the Series B note holders are either fully cash secured through debt service accounts or have been completely repaid. Variable rate interest accrues on the subordinated note at LIBOR plus 0.5%. The weighted-average variable interest rates charged on this note at December 31, 2009 and 2008 were 1.59% and 3.62%, respectively. At December 31, 2009 and 2008, the amount of accrued but unpaid interest on the LL&E Note was approximately $10.2 million and $9.8 million, respectively.

Note 12. Equity and Distributions

Our common units represent limited partner interests, which give the 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").

Capital accounts, as defined in our Partnership Agreement, are maintained by us for our general partner and our limited partners. The capital account provisions of our Partnership Agreement incorporate principles established for U.S. Federal income tax purposes and are not comparable to the equity accounts reflected under GAAP in our financial statements. Earnings and cash distributions are allocated to our partners in accordance with their respective percentage interests.

In February 2007, we completed our initial public offering of 14,950,000 common units (including an overallotment of 1,950,000 common units), which generated net cash proceeds of $290.5 million. As consideration for the DEP I drop down transaction (see Note 1), we distributed $260.6 million of the net cash proceeds from our IPO plus $198.9 million in borrowings and a net 5,351,571 common units to EPO. We used $38.5 million of the overallotment proceeds to redeem 1,950,000 of the 7,301,571 common units we originally issued to EPO in connection with the DEP I drop down transaction, resulting in a final amount of 5,351,571 common units beneficially owned by EPO.

Class B Units

Our limited partners' equity account balance at December 31, 2008 reflected the issuance to EPO of 37,333,887 Class B units, which were used along with proceeds borrowed under the Term Loan Agreement to acquire the DEP II Midstream Businesses in December 2008. In February 2009, the Class B units were converted on a one-to-one basis into common units.

Registration Statements and Equity Offerings

We have a universal shelf registration statement on file with the SEC that allows us to issue up to $1 billion in debt and equity securities for general partnership purposes. After taking into account a June 2009 equity offering made under this registration statement (see below), we can issue approximately $856.4 million of additional securities under this registration statement in the future.

In June 2009, we issued 8,000,000 common units to the public at an offering price of $16.00 per unit. We granted the underwriters of this offering a 30-day option to purchase up to 1,200,000 additional common units to cover over-allotments, which they exercised for 943,400 common units in July 2009. We generated net cash proceeds of approximately $137.4 million from this underwritten equity offering. The net proceeds were used to repurchase an equal number of our common units beneficially owned by EPO. The repurchased common units were subsequently cancelled.

In December 2009, we filed a registration statement with the SEC authorizing the issuance of up to an aggregate 2,000,000 common units in connection with a distribution reinvestment plan ("DRIP"). The DRIP gives unitholders of record and beneficial owners of our common units the ability to increase the number of our common units they own through voluntarily reinvesting their quarterly cash distributions into the purchase of additional common units. Plan participants may purchase our common units at a discount ranging from 0% to 5% (currently set at 5%), which will be set from time to time by us. We did not issue any common units under the DRIP during the year ended December 31, 2009.

In February 2010, we filed a registration statement with the SEC authorizing the issuance of up to 1,000,000 common units in connection with an employee unit purchase plan and a long-term incentive plan. These plans became effective on February 11, 2010. See Note 5 for additional information.

Unit History

The following table details changes in our outstanding common units since our initial public offering on February 5, 2007:

	Limited Partner Units	Treasury Units	Total Outstanding Units
Activity on February 5, 2007:			
Common units originally issued to EPO in connection with the DEP I drop down transaction	7,301,571	--	7,301,571
Common units issued in connection with our IPO	14,950,000	--	14,950,000
Redemption of common units using proceeds from IPO overallotment	(1,950,000)	--	(1,950,000)
Common units outstanding, December 31, 2007	20,301,571	--	20,301,571
Common units sold to EPO in connection with the DEP II drop down transaction	41,529	--	41,529
Common units outstanding, December 31, 2008	20,343,100	--	20,343,100
Conversion of Class B units to common units on February 1, 2009	37,333,887	--	37,333,887
June 2009 underwritten offering	8,000,000	--	8,000,000
Acquisition of common units from EPO in June 2009	(8,000,000)	8,000,000	--
Cancellation of treasury units in June 2009	--	(8,000,000)	(8,000,000)
Additional units issued in July 2009 in connection with June 2009 underwritten offering	943,400	--	943,400
Acquisition of common units from EPO in July 2009	(943,400)	943,400	--
Cancellation of treasury units in July 2009	--	(943,400)	(943,400)
Common units outstanding, December 31, 2009	57,676,987	--	57,676,987

Distributions

Our partnership agreement requires us to distribute all of our available cash (as defined in our Partnership Agreement) to our partners on a quarterly basis. Such distributions are not cumulative. In addition, we do not have a legal obligation to pay distributions at our initial distribution rate or at any other rate. Our general partner has no incentive distribution rights. The following table presents the amount, record date and payment date of the quarterly cash distributions we paid on each of our common units with respect to each quarterly period since our IPO.

	Cash Distribution History		
	Per Unit	Record Date	Payment Date
2008			
1st Quarter	0.4100	April 30, 2008	May 7, 2008
2nd Quarter	0.4200	July 31, 2008	August 7, 2008
3rd Quarter	0.4200	October 31, 2008	November 12, 2008
4th Quarter (1)	0.4275	January 30, 2009	February 9, 2009
2009			
1st Quarter	0.4300	April 30, 2009	May 8, 2009
2nd Quarter	0.4350	July 31, 2009	August 7, 2009
3rd Quarter	0.4400	October 30, 2009	November 5, 2009
4th Quarter	0.4450	January 29, 2010	February 5, 2010

(1) We issued 37.3 million Class B units in connection with the DEP II drop down. The Class B units received a cash distribution of $0.1115 per unit for the distribution that Duncan Energy Partners paid with respect to the fourth quarter of 2008, which represented the regular quarterly distribution pro-rated for the 24-day period from December 8, 2008, the closing date of the DEP II drop down transaction, to December 31, 2008. These units automatically converted on a one-for-one basis to common units on February 1, 2009.

Accumulated Other Comprehensive Loss

Our AOCI balance, which was related to interest rate derivative instruments, reflected losses of $5.4 million and $9.6 million at December 31, 2009 and December 31, 2008, respectively.

Note 13. Noncontrolling Interest

We account for EPO's retained ownership interests in each of the DEP I and DEP II Midstream Businesses as a noncontrolling interest. Under this method of presentation, all revenues and expenses of these businesses are included in consolidated net income and EPO's share (as Parent) of the income 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 Consolidated Balance Sheets.

DEP I Midstream Businesses – Parent

The DEP I Midstream Businesses allocate their net income (or loss) to us and EPO based on our respective sharing ratios, which are currently 66% to us and 34% to EPO. In deriving the net income (or loss) of Mont Belvieu Caverns to be allocated between us and EPO, certain special allocations are required as follows:

§ EPO is allocated all operational measurement gains and losses; and

§ EPO is allocated 100% of the depreciation expense related to capital projects that it has fully funded.

Distributions paid to us and EPO by the DEP I Midstream Businesses are in accordance with each owner's respective sharing ratio. In general, contributions made by us and EPO to the DEP I Midstream Businesses are in accordance with the previously noted sharing ratios. However, special funding arrangements exist under the terms of an Omnibus Agreement and the limited liability company agreement of Mont Belvieu Caverns (the "Caverns LLC Agreement"). See Note 15 for additional information regarding these related party agreements.

In accordance with the Omnibus Agreement, EPO agreed to fund all of the capital expenditures incurred by South Texas NGL and Mont Belvieu Caverns with respect to certain expansion projects that were underway at the time of our initial public offering in February 2007. EPO made aggregate cash contributions to South Texas NGL and Mont Belvieu Caverns of $1.4 million and $32.5 million in connection with these capital projects during the years ended December 31, 2009 and 2008, respectively. The majority of these contributions related to funding Phase II expansion costs of the South Texas NGL pipeline. This project was completed in 2008. EPO will not receive an increased allocation of income or cash distributions as a result of these contributions to South Texas N GL and Mont Belvieu Caverns.

EPO made cash contributions of $16.6 million and $99.5 million under the Caverns LLC Agreement during the years ended December 31, 2009 and 2008, respectively, to fund 100% of certain storage-related projects sponsored by EPO's NGL marketing activities. We elected to not participate in such projects. EPO is not expected to receive an increased allocation of earnings or cash flows as a result of these contributions to Mont Belvieu Caverns. Additional contributions of approximately $32.7 million are expected from EPO to fund such projects in 2010. The constructed assets will be the property of Mont Belvieu Caverns.

In accordance with the Caverns LLC Agreement, EPO is required each period to contribute cash to Mont Belvieu Caverns for net operational measurement losses and is entitled to receive distributions from Mont Belvieu Caverns for net operational measurement gains. We continue to record operational measurement gains and losses associated with our Mont Belvieu storage complex. Such amounts are included in operating costs and expenses and gross operating margin. However, these operational measurement gains and losses do not impact net income attributable to Duncan Energy Partners since they are allocated to EPO. We have not established a reserve for operational measurement losses on our balance sheet.

The following table presents our calculation of "Net income attributable to noncontrolling interest – DEP I Midstream Businesses – Parent" for the years ended December 31, 2009, 2008 and 2007.

	For the Year Ended December 31,		
	2009	2008	2007
Total net income of DEP I Midstream Businesses, prior to special allocations	$ 68.0	$ 56.4	$ 45.4
Multiplied by Parent 34% interest in net income	x 34%	x 34%	x 34%
Parent 34% interest in net income, prior to special allocations	23.1	19.2	15.5
Add (deduct) operational measurement gain (loss) allocated to Parent	(1.7)	(6.8)	4.5
Less depreciation expense related to fully funded projects allocated to Parent	(6.1)	(1.0)	--
Net income attributable to noncontrolling interest – DEP I Midstream Businesses – Parent	$ 15.3	$ 11.4	$ 20.0

The following table provides a reconciliation of the amounts presented as "Noncontrolling interest in subsidiaries – DEP I Midstream Businesses – Parent" on our consolidated balance sheets at December 31, 2009 and 2008:

December 31, 2007 balance	$ 355.2
Net income attributable to noncontrolling interest – DEP I Midstream Businesses – Parent	11.4
Contributions made by EPO to South Texas NGL and Mont Belvieu Caverns in connection with the following agreements:	
Caverns LLC Agreement	88.1
Omnibus Agreement	31.4
Other contributions made by EPO to the DEP I Midstream Businesses	36.5
Cash distributions paid to EPO by the DEP I Midstream Businesses	(44.2)
December 31, 2008 balance	478.4
Net income attributable to noncontrolling interest – DEP I Midstream Businesses – Parent	15.3
Contributions made by EPO to South Texas NGL and Mont Belvieu Caverns in connection with the following agreements:	
Caverns LLC Agreement	16.6
Omnibus Agreement	1.4
Other contributions made by EPO to the DEP I Midstream Businesses	0.9
Cash distributions paid to EPO by the DEP I Midstream Businesses	(25.3)
December 31, 2009 balance	$ 487.3

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 22.6% of the equity of the DEP II Midstream Businesses. EPO retained the remaining 77.4% of equity. The 22.6% and 77.4% amounts are referred to as the "Percentage Interests," and represent each owner's initial relative economic investment in the DEP II Midstream Businesses at December 8, 2008.

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

The annualized return rate is applied to each party's aggregate investment (or "Distribution Base") in the DEP II Midstream Businesses. To the extent that we and/or EPO make capital contributions to fund expansion capital projects involving the DEP II Midstream Businesses, the Distribution Base of the contributing member will be increased by that member's capital contribution at the time such contribution is made. At December 8, 2008 and December 31, 2009, our Distribution Base was $730.0 million. EPO's Distribution Base was $452.1 million and $817.9 million at December 8, 2008 and December 31, 2009, respectively. The increase in EPO's Distribution Base is the result of its decision to fund 100% of the expans ion capital projects of the DEP II Midstream Businesses since December 8, 2008. We have not yet participated in the expansion capital project spending of the DEP II Midstream Businesses, although we may elect to invest in existing or future expansion projects at a later date.

Net income (or loss) of the DEP II Midstream Businesses is first allocated to us and EPO based on each entity's Percentage Interest of 22.6% and 77.4%, respectively, and then in a manner that in part follows the cash distributions paid by (or contributions made to) each 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 wh en we are allocated income. It is our expectation that EPO will be allocated a loss by the DEP II Midstream Businesses until such time as expansion capital projects such as the Sherman Extension and Trinity River Lateral realize their income and cash flow potential. 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.

The following table presents the allocation of net income of the DEP II Midstream Businesses for the 24-day period extending from December 8, 2008 to December 31, 2008.

	DEP		EPO
Total net income of DEP II Midstream Businesses		$ 0.5	$ 0.5
Multiplied by each owner's Percentage Interest		22.6%	77.4%
Base earnings allocation to each owner		0.1	0.4
Additional earnings allocation to Duncan Energy Partners:			
Total distributions paid by the DEP II Midstream Businesses with respect to period	$ 5.4		
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	1.2		
Less actual distributions paid to Duncan Energy Partners with respect to period based on annualized return for period	5.6	4.4	(4.4)
Net income attributable to Duncan Energy Partners		$ 4.5	
Net loss attributable to EPO as noncontrolling interest			$ (4.0)

The following table presents the allocation of net income of the DEP II Midstream Businesses for the year ended December 31, 2009:

		DEP	EPO
Total net loss of DEP II Midstream Businesses		$ (0.5)	$ (0.5)
Multiplied by each owner's Percentage Interest		22.6%	77.4%
Base earnings allocation to each owner		(0.1)	(0.4)
Additional earnings allocation to Duncan Energy Partners:			
Total distributions paid by the DEP II Midstream Businesses with respect to period	$ 116.3		
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	26.3		
Less actual distributions paid to Duncan Energy Partners with respect to period based on annualized return for period	86.5	60.2	(60.2)
Net income attributable to Duncan Energy Partners		$ 60.1	
Net loss attributable to EPO as noncontrolling interest			$ (60.6)

We and EPO received $86.5 million and $29.8 million, respectively, in cash distributions from the DEP II Midstream Businesses for the twelve months ended December 31, 2009. The $86.5 million (or, approximately, $21.6 million each quarter) received by us with respect to 2009 represents the annualized return rate for 2009 of 11.85% multiplied by our Distribution Base of $730.0 million. As a result, we received our expected Tier I distributions for the period. Based on EPO's Distribution Base throughout 2009, it was entitled to $83.4 million of Tier II distributions, of which it received only $29.8 million. No Tier III distributions were paid by the DEP II Midstream Businesses with respect to 2009.

The following table provides a reconciliation of the amounts presented as "Noncontrolling interest in subsidiaries – DEP II Midstream Businesses – Parent" on our Consolidated Balance Sheets at December 31, 2009 and 2008. Amounts are for the period from the closing of the drop down transaction to December 31, 2009.

Retention by Parent of ownership interest in DEP II Midstream Businesses on December 8, 2008	$ 2,595.5
Net loss attributable to noncontrolling interest – DEP II Midstream Businesses – Parent	(4.0)
Contributions by EPO in connection with expansion cash calls	21.3
Distributions to noncontrolling interest of subsidiary operating cash flows	(0.8)
Other general cash contributions from noncontrolling interest	1.0
December 31, 2008 balance	$ 2,613.0
Net loss attributable to noncontrolling interest – DEP II Midstream Businesses – Parent	(60.6)
Contributions by EPO in connection with expansion cash calls	344.5
Distributions to noncontrolling interest of subsidiary operating cash flows	(31.8)
Other general cash contributions from noncontrolling interest	23.1
December 31, 2009 balance	$ 2,888.2

For additional information regarding our agreements with EPO in connection with the DEP II drop down transaction, see "Significant Relationships and Agreements with EPO – Company and Limited Partnership Agreements – DEP II Midstream Businesses" under Note 15.

Note 14. Business Segments

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

We evaluate segment performance based on the non-GAAP financial measure of gross operating margin. Gross operating margin (either in total or by individual segment) is an important performance measure of the core profitability of our operations. This measure forms the basis of our internal financial reporting and is used by management in deciding how to allocate capital resources among business segments. We believe that investors benefit from having access to the same financial measures that management uses in evaluating segment results. The GAAP financial measure most directly comparable to total segment gross operating margin is operating income.

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

Segment revenues include intersegment and intrasegment transactions. Our consolidated revenues reflect the elimination of all material intercompany transactions.

We include equity earnings from Evangeline in our measurement of segment gross operating margin and operating income. Our equity investments in midstream energy operations such as those conducted by Evangeline are a vital component of our long-term business strategy and important to the operations of Acadian Gas. This method of operation enables us to achieve favorable economies of scale relative to our level of investment and also lowers our exposure to business risks compared to the profile we would have on a stand-alone basis. Our equity investee is within the same industry as our consolidated operations, thus we believe treatment of earnings from our equity method investee as a component of gross operating margin and operating income is appropriate.

Segment assets consist of property, plant and equipment, our investment in Evangeline, intangible assets and goodwill. The carrying values of such amounts are assigned to each segment based on each asset’s or investment’s principal operations and contribution to the gross operating margin of that particular segment. Since construction-in-progress amounts (which are a component of property, plant and equipment) generally do not contribute to segment gross operating margin, such amounts are excluded from segment asset totals until they are placed in service. Consolidated intangible assets and goodwill are assigned to each segment based on the classification of the assets to which they relate.

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

	For the Year Ended December 31,		
	2009	2008	2007
Revenues	$ 979.3	$ 1,598.1	$ 1,220.3
Less: Operating costs and expenses	(908.3)	(1,512.8)	(1,171.0)
Add: Equity in income of Evangeline	1.1	0.9	0.2
Depreciation, amortization and accretion in operating costs and expenses (1)	186.3	167.3	175.3
Impairment charge included in operating costs and expenses	4.2	--	--
Gain on asset sales and related transactions in operating costs and expenses	(0.5)	(0.5)	(0.1)
Total segment gross operating margin	$ 262.1	$ 253.0	$ 224.7

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

The following table presents a reconciliation of total segment gross operating margin to operating income and further to GAAP net income for the periods noted:

	For the Year Ended December 31,		
	2009	2008	2007
Total segment gross operating margin	$ 262.1	$ 253.0	$ 224.7
Adjustments to reconcile total segment gross operating margin to operating income:			
Depreciation, amortization and accretion in operating costs and expenses (1)	(186.3)	(167.3)	(175.3)
Impairment charge included in operating costs and expenses	(4.2)	--	--
Gain on asset sales and related transactions in operating costs and expenses	0.5	0.5	0.1
General and administrative costs	(11.2)	(18.3)	(13.1)
GAAP operating income	60.9	67.9	36.4
Other expense, net	(13.8)	(11.5)	(8.6)
Provision for income taxes	(1.3)	(1.1)	(4.2)
GAAP net income	$ 45.8	$ 55.3	$ 23.6

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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

	Natural Gas Pipelines & Services	NGL Pipelines & Services	Petrochemical Services	Adjustments and Eliminations	Consolidated Totals
Revenues from third parties:					
Year ended December 31, 2009	$ 390.2	$ 88.2	$ 13.6	$ --	$ 492.0
Year ended December 31, 2008	773.1	69.1	14.2	--	856.4
Year ended December 31, 2007	685.2	59.7	14.4	--	759.3
Revenues from related parties:					
Year ended December 31, 2009	348.5	138.8	--	--	487.3
Year ended December 31, 2008	582.2	159.5	--	--	741.7
Year ended December 31, 2007	323.2	134.8	3.0	--	461.0
Total revenues:					
Year ended December 31, 2009	738.7	227.0	13.6	--	979.3
Year ended December 31, 2008	1,355.3	228.6	14.2	--	1,598.1
Year ended December 31, 2007	1,008.4	194.5	17.4	--	1,220.3
Equity in income of Evangeline:					
Year ended December 31, 2009	1.1	--	--	--	1.1
Year ended December 31, 2008	0.9	--	--	--	0.9
Year ended December 31, 2007	0.2	--	--	--	0.2
Gross operating margin by individual business segment and in total:					
Year ended December 31, 2009	148.2	103.4	10.5	--	262.1
Year ended December 31, 2008	159.0	82.9	11.1	--	253.0
Year ended December 31, 2007	122.5	87.9	14.3	--	224.7
Segment assets:					
At December 31, 2009	3,340.8	946.1	83.3	233.7	4,603.9
At December 31, 2008	2,909.8	936.5	86.6	459.0	4,391.9
At December 31, 2007	2,716.6	731.5	89.6	257.3	3,795.0
Property, plant and equipment:					
At December 31, 2009	3,318.8	913.8	83.3	233.7	4,549.6
At December 31, 2008	2,887.5	897.1	86.6	459.0	4,330.2
At December 31, 2007	2,693.8	697.3	89.6	257.3	3,738.0
Investment in Evangeline: (see Note 9)					
At December 31, 2009	5.6	--	--	--	5.6
At December 31, 2008	4.5	--	--	--	4.5
At December 31, 2007	3.5	--	--	--	3.5
Intangible assets:					
At December 31, 2009	12.0	31.8	--	--	43.8
At December 31, 2008	13.4	38.9	--	--	52.3
At December 31, 2007	14.9	33.7	--	--	48.6
Goodwill:					
At December 31, 2009	4.4	0.5	--	--	4.9
At December 31, 2008	4.4	0.5	--	--	4.9
At December 31, 2007	4.4	0.5	--	--	4.9

Our consolidated revenues were earned in the United States. Our operations are located in Texas and Louisiana. Our largest third-party customer was Exxon Mobil, which accounted for 7.5%, 10.0% and 7.6% of our consolidated revenues in 2009, 2008 and 2007, respectively. The majority of our revenues from Exxon Mobil is derived from the sale and transportation of natural gas and is also presented in our Natural Gas Pipelines & Services business segment. Sales to Exxon Mobil totaled $73.4 million, $159.2 million and $93.2 million for the years ended December 31, 2009, 2008 and 2007, respectively.

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

	For the Year Ended December 31,		
	2009	2008	2007
Natural Gas Pipelines & Services:			
Sales of natural gas	$ 460.2	$ 1,100.2	$ 794.1
Natural gas transportation services	263.2	246.7	212.8
Natural gas storage services	15.3	8.4	1.5
Total	$ 738.7	$ 1,355.3	$ 1,008.4
NGL Pipelines & Services:			
Sales of NGLs	$ 35.0	$ 47.9	$ 40.3
Sales of other products	11.3	15.0	10.8
NGL and petrochemical storage services	104.9	87.4	68.9
NGL fractionation services	29.5	32.4	30.3
NGL transportation services	43.8	43.6	42.5
Other services	2.5	2.3	1.7
Total	$ 227.0	$ 228.6	$ 194.5
Petrochemical Services:			
Propylene transportation services	$ 13.6	$ 14.2	$ 17.4
Total consolidated revenues	$ 979.3	$ 1,598.1	$ 1,220.3
Consolidated cost and expenses			
Operating costs and expenses:			
Cost of natural gas and NGL sales	$ 479.7	$ 1,123.9	$ 815.8
Depreciation, amortization and accretion	186.3	167.4	175.3
Gain on asset sales and related transactions	(0.5)	(0.5)	(0.1)
Other operating expenses	242.8	222.0	180.0
General and administrative costs	11.2	18.3	13.1
Total consolidated costs and expenses	$ 919.5	$ 1,531.1	$ 1,184.1

Changes in our revenues and operating costs and expenses year-to-year 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 natural gas and NGLs; however, these higher commodity prices also increase the associated cost of sales as purchase prices rise.

Note 15. Related Party Transactions

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

	For the Year Ended December 31,		
	2009	2008	2007
Revenues:			
Revenues from EPO:			
Sales of natural gas	$ 141.9	$ 177.3	$ 29.6
Natural gas transportation services	56.4	51.5	35.8
Natural gas storage services	2.6	0.9	--
Sales of NGLs	33.7	52.9	41.2
NGL and petrochemical storage services	36.2	35.2	28.9
NGL fractionation services	32.0	29.7	30.3
NGL transportation services	28.6	30.4	27.6
Other services	--	--	3.0
Sales of natural gas – Evangeline	155.5	362.9	264.2
Natural gas transportation services – Energy Transfer Equity	0.1	0.9	0.4
NGL and petrochemical storage services – Energy Transfer Equity	0.3	--	--
Total related party revenues	$ 487.3	$ 741.7	$ 461.0
Operating costs and expenses:			
EPCO administrative services agreement	$ 85.8	$ 72.1	$ 63.7
Expenses with EPO:			
Purchases of natural gas	52.1	229.9	29.1
Operational measurement losses (gains)	1.7	6.8	(4.5)
Other expenses with EPO	16.4	18.4	7.4
Purchases of natural gas – Nautilus	1.7	10.3	3.5
Expenses with Energy Transfer Equity:			
Purchases of natural gas	5.7	7.3	5.6
Operating cost reimbursements for shared facilities	(3.4)	(2.8)	(1.7)
Other expenses with Energy Transfer Equity	(0.7)	3.1	1.1
Other related party expenses, primarily with Evangeline	--	--	0.1
Total related party operating costs and expenses	$ 159.3	$ 345.1	$ 104.3
General and administrative costs:			
EPCO administrative services agreement	$ 10.9	$ 15.7	$ 11.5
Other related party general and administrative costs	--	(0.8)	(0.1)
Total related party general and administrative costs	$ 10.9	$ 14.9	$ 11.4

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

	December 31, 2009	December 31, 2008
Accounts receivable – related parties		
EPO and affiliates (1)	$ 54.3	$ 2.3
Energy Transfer Equity and affiliates	0.2	0.9
Other	--	0.1
Total	$ 54.5	$ 3.3
Accounts payable – related parties		
EPO and affiliates	$ 5.5	$ 46.1
EPCO and affiliates	8.1	2.4
Total	$ 13.6	$ 48.5

(1) EPO borrowed $45.6 million under a Master Intercompany Loan Agreement. See “Significant Relationships and Agreements with EPO” under this Note 15 for more information.

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

Significant Relationships and Agreements with EPO

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

At December 31, 2009, EPO beneficially owned approximately 58.6% of our limited partner interests and 100% of our general partner. EPO was sponsor of the DEP I and DEP II drop down transactions and owns varying interests (as Parent) in the DEP I and DEP II Midstream Businesses. For a description of the DEP I and DEP II drop down transactions (including consideration provided to EPO), see Note 1. 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 13. EPO may contribute or sell other equity interests or assets to us; however, EPO has no obligations or commitment to make such contributions or sales to us.

EPO has continued involvement with all of our subsidiaries, including the following types of transactions: (i) it utilizes our storage services to support its Mont Belvieu fractionation and other businesses; (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 is owned by us.

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 borrowed $1.3 million and EPO borrowed $45.6 million under the agreement at a market rate of interest. EPO's intercompany borrowing is a component of "Accounts receivable – related parties" on our Consolidated Balance Sheets. These amounts were subsequently repaid on January 4, 2010. The interest rate applicable to these short-term borrowings was 0.73%. Amounts borrowed by us and the related interest el iminate in consolidation.

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

§ indemnification for certain environmental liabilities, tax liabilities and right-of-way defects with respect to the DEP I and DEP II Midstream Businesses EPO contributed to us in connection with the respective drop down transactions;

§ funding by EPO of 100% of 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 IPO;

§ funding by EPO of 100% of post-December 8, 2008 capital expenditures to complete the Sherman Extension natural gas pipeline;

- § a right of first refusal to EPO 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; and

- § a preemptive right with respect to equity securities issued by certain of our subsidiaries, other than as consideration in an acquisition or in connection with a loan or debt financing.

We and EPO have also 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.

Our general partner’s Audit, Conflicts and Governance (“ACG”) Committee must approve amendments to the Omnibus Agreement when such amendments would adversely affect our unitholders.

Neither EPO nor any of its affiliates are restricted under the Omnibus Agreement from competing against us. As provided for in the EPCO ASA, EPO and its affiliates may acquire, construct or dispose of additional midstream energy or other assets in the future without any obligation to offer us the opportunity to acquire or construct such assets.

As noted previously, EPO indemnified us for certain environmental liabilities, tax liabilities and right-of-way defects associated with the assets it contributed to us in connection with the DEP I and DEP II drop down transactions. These indemnifications terminated on February 5, 2010. There is an aggregate cap of $15.0 million on the amount of indemnity coverage and we are not entitled to indemnification until the aggregate amount of claims we incur exceeds $250 thousand. Environmental liabilities resulting from a change of law after February 5, 2007 are excluded from the indemnity. We made no claims to EPO during the years ended December 31, 2009 and 2008.

For information regarding the funding by EPO of 100% of certain post-February 5, 2007 capital expenditures of South Texas NGL and Mont Belvieu Caverns, see “Noncontrolling Interest – DEP I Midstream Businesses – Parent” under Note 13.

Mont Belvieu Caverns’ LLC Agreement. The Caverns LLC Agreement states that if Duncan Energy Partners elects to not participate in certain 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 pr ojects from EPO within 90 days of such projects being placed in service. In November 2008, the Caverns LLC Agreement was amended to provide that EPO would prospectively receive a special allocation of 100% of the depreciation related to 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 13.

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 provide for the following:

- § the acquisition by us from EPO 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;

- the payment of distributions in accordance with an overall "waterfall" approach that stipulates that to the extent that the DEP II Midstream Businesses collectively generate cash sufficient to pay distributions to their partners or members, such cash will be distributed first to us and then to EPO in amounts sufficient to generate an aggregate annualized fixed return on their respective investments of 11.85%. Distributions in excess of these amounts will be distributed 98.0% to EPO and 2.0% to us. The initial annual fixed return amount of 11.85% will be increased by 2.0% each calendar year beginning January 1, 2010. For example, the fixed return in 2010, assuming no other adjustments, would be 102% of 11.85%, or 12.087%;

- the funding of operating cash flow deficits in accordance with each owner's respective partner or member interest;

- the election by either owner to fund cash calls associated with expansion capital projects. Since December 8, 2008, we have elected to not participate in such cash calls and, as a result, EPO has funded 100% of the expansion project costs of the DEP II Midstream Businesses. If we later elect to participate in any expansion projects, then we will be required to make a capital contribution for our share of the project costs.

Any capital contributions to fund expansion projects made by either us or EPO will increase such partner's Distribution Base (and hence future priority return amounts) under the company agreement of Enterprise Texas. As noted, we have declined participation in expansion project spending since December 8, 2008. As a result, EPO has funded 100% of such growth capital spending and its Distribution Base has increased from $452.1 million at December 8, 2008 to $817.9 million at December 31, 2009. The DEP Distribution Base was unchanged at $730.0 million at December 31, 2009.

Common Unit Purchase Agreement – June 2009 Equity Offering. Pursuant to a common unit purchase agreement, we repurchased 8,000,000 of our common units beneficially owned by EPO in June 2009. We repurchased an additional 943,400 of our common units beneficially owned by EPO in July 2009. The repurchase of common units beneficially owned by EPO was reviewed and approved by each of the ACG Committees of EPGP and DEP GP. See Note 12 for additional information regarding our June 2009 equity offering.

Transactions with TEPPCO. Beginning in 2008, Mont Belvieu Caverns commenced providing NGL and petrochemical storage services to TEPPCO. For the period January 2007 through March 2008, we leased from TEPPCO an 11-mile pipeline that was part of our South Texas NGL System. We discontinued this lease during the first quarter of 2008 when we completed the construction of a parallel pipeline. All of our related party activities and balances with TEPPCO, prior to their merger with EPO, have been aggregated with related party activities and balances that we present for EPO.

Relationship with EPCO

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

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

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

§ EPCO will allow us to participate as named insureds in its overall insurance program, with the associated premiums and other costs being allocated to us.

Our operating costs and expenses include amounts paid to EPCO for the costs it incurs to operate our facilities, including compensation of 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 compensation of employees. In general, our reimbursement to EPCO for administrative services is either (i) on an actual basis for direct expenses it may incur on our behalf (e.g., the purchase of office supplies) or (ii) based on an allocation of such charges between the various parties to the ASA based on the estimated use of such services by each party (e.g., the allocation of general le gal 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 indicated:

	For Year Ended December 31,		
	2009	2008	2007
Operating costs and expenses	$ 85.8	$ 72.1	$ 63.7
General and administrative expenses	10.9	15.7	11.5
Total costs and expenses	$ 96.7	$ 87.8	$ 75.2

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

The ASA also addresses potential conflicts that may arise among Enterprise Products Partners (including EPGP), Enterprise GP Holdings (including EPE Holdings), Duncan Energy Partners (including DEP GP), and the EPCO Group. The EPCO Group includes EPCO and its other affiliates, but excludes Enterprise Products Partners, Enterprise GP Holdings, Duncan Energy Partners and their respective general partners.

The ASA was amended on January 30, 2009 to provide for the cash reimbursement by us, Enterprise Products Partners and Enterprise GP Holdings to EPCO of distributions of cash or securities, if any, made by EPCO Unit to their respective Class B limited partners. The ASA amendment also extended the term under which EPCO provides services to the partnership entities from December 2010 to December 2013 and made other updating and conforming changes.

Relationship with Evangeline

Acadian Gas sold $155.5 million, $362.9 million and $264.2 million of natural gas to Evangeline, under its natural gas purchase contract with Evangeline, during the years ended December 31, 2009, 2008 and 2007, respectively. The amount of natural gas purchased by Evangeline pursuant to this contract averaged approximately 50 BBtus/d during the twelve months ended December 31, 2009, 2008 and 2007, respectively. For the years ended December 31, 2008 and 2007, Evangeline was our largest customer and accounted for 22.7% and 21.7%, respectively, of our consolidated revenues. For the year ended December 31, 2009, another related party was our largest customer.

Relationship with Energy Transfer Equity

Enterprise GP Holdings acquired equity method investments in Energy Transfer Equity, L.P. (together with its consolidated subsidiaries, "Energy Transfer Equity") and its general partner in May 2007.

As a result of common control of Enterprise GP Holdings and us, Energy Transfer Equity became a related party to us. Our revenues from Energy Transfer Equity are attributable to natural gas transportation services. Our related party expenses with Energy Transfer Equity primarily include natural gas purchases for pipeline imbalances, reimbursements of operating costs for shared facilities and the lease of a pipeline in south Texas.

Note 16. Earnings Per Unit

Basic earnings per unit is computed by dividing net income or loss attributable to Duncan Energy Partners allocated to limited partner interests by the weighted-average number of distribution-bearing common and Class B units (see Note 12) outstanding during a period. We have no dilutive securities.

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

	For the Year Ended December 31,		
	2009	**2008**	**2007**
Net income attributable to Duncan Energy Partners L.P.	$ 91.1	$ 47.9	$ 3.6
Subtract: Income allocated to former owners of DEP I Midstream Businesses	--	--	(5.0)
Add (subtract): Loss (income) allocated to former owners of the DEP II Midstream Businesses	--	(19.6)	20.6
Net income allocated to Duncan Energy Partners	91.1	28.3	19.2
Multiplied by DEP GP ownership interest (weighted-average for period)	0.7%	1.7%	2.0%
Net income allocation to DEP GP	$ 0.6	$ 0.5	$ 0.4

From the closing of our initial public offering on February 5, 2007 through December 7, 2008, DEP GP maintained a 2% general partner interest in us. On December 8, 2008, DEP GP elected to forego making a cash contribution to us to maintain its 2.0% general partner interest in connection with the DEP II drop down transaction. As a result, DEP GP's general partner interest was reduced to 0.7% beginning December 8, 2008.

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

	For the Year Ended December 31,		
	2009	**2008**	**2007**
Net income allocation to Duncan Energy Partners	$ 91.1	$ 28.3	$ 19.2
Less: Income allocation to DEP GP	0.6	0.5	0.4
Net income allocation to limited partners	$ 90.5	$ 27.8	$ 18.8
Basic and diluted earnings per unit:			
Numerator (net income allocation to limited partners)	$ 90.5	$ 27.8	18.8
Denominator (weighted-average units outstanding):			
Common units	54.5	20.3	20.3
Class B units	3.2	2.5	--
Total units	57.7	22.8	20.3
Earnings per unit	$ 1.57	$ 1.22	$ 0.93

Note 17. Commitments and Contingencies

Litigation

On occasion, we are named as a defendant in litigation relating to our normal business operations, including regulatory and environmental matters. Although we insure against various business risks to the extent we believe it is prudent, there is no assurance that the nature and amount of such insurance will be adequate, in every case, to indemnify us against liabilities arising from future legal proceedings as a result of our ordinary business activity. We are not aware of any litigation, pending or threatened, that we believe is reasonably likely to have a significant adverse effect on our financial position, results of operations or cash flows.

Redelivery Commitments

We transport and store natural gas and NGLs and store petrochemical products for third parties under various contracts. These volumes are: (i) accrued as product payables on our Consolidated Balance Sheets; (ii) in transit for delivery to our customers; or (iii) held at our storage facilities for redelivery to our customers. We are insured against any physical loss of such volumes due to catastrophic events. Under the terms of our NGL and petrochemical product storage agreements, we are generally required to redeliver volumes to the owner on demand. At December 31, 2009, NGL and petrochemical products aggregating 20.9 million barrels were due to be redelivered to their owners along with 5,015 BBtus of natural gas. See Note 2 for more information regarding accrued product payables.

Regulatory Matters

Certain recent scientific studies have suggested that emissions of certain gases, commonly referred to as “greenhouse gases” and including carbon dioxide and methane, may be contributing to climate change. On June 26, 2009, the U.S. House of Representatives passed the “American Clean Energy and Security Act of 2009,” or “ACESA,” which would establish an economy-wide cap-and-trade program intended to reduce the emissions of greenhouse gases in the United States and would require most sources of greenhouse gas emissions to obtain greenhouse gas emission “allowances” corresponding to their annual emissions of greenhouse gases. The U.S. Senate has also begun work on its own legislation for controlling and reducing emission s of greenhouse gases in the United States. In addition, on December 7, 2009, the U.S. Environmental Protection Agency (“EPA”) announced its finding that emissions of greenhouse gases presented an endangerment to human health and the environment. These findings by the EPA allow the agency to proceed with the adoption and implementation of regulations that would restrict emissions of greenhouse gases under existing provisions of the federal Clean Air Act. Although it may take the EPA several years to adopt and impose regulations limiting emissions of greenhouse gases, any such regulation could require us to incur costs to reduce emissions of greenhouse gases associated with our operations. Any laws or regulations that may be adopted to restrict or reduce emissions of greenhouse gases would likely require us to incur increased operating costs, and may have an adverse effect on our business, financial position, demand for our operations, results of operati ons and cash flows.

Contractual Obligations

The following table summarizes our significant contractual obligations at December 31, 2009. A description of each type of contractual obligation follows (dollars in millions):

	Payment or Settlement due by Period						
Contractual Obligations (1)	**Total**	**2010**	**2011**	**2012**	**2013**	**2014**	**Thereafter**
Scheduled maturities of long term debt (2)	$ 457.3	$ --	$ 457.3	$ --	$ --	$ --	$ --
Estimated cash interest payments (3)	$ 14.8	$ 11.1	$ 3.7	$ --	$ --	$ --	$ --
Operating lease obligations	$ 115.6	$ 9.0	$ 8.9	$ 8.7	$ 7.4	$ 6.6	$ 75.0
Purchase obligations:							
Product purchase commitments:							
Estimated payment obligations:							
Natural gas	$ 511.7	$ 257.3	$ 127.0	$ 127.4	$ --	$ --	$ --
Other	$ 0.1	$ *	$ *	$ *	$ --	$ --	$ --
Underlying major volume commitments:							
Natural gas (in BBtus)	77,207	40,657	18,250	18,300	--	--	--
Capital expenditure commitments (4)	$ 175.3	$ 175.3	$ --	$ --	$ --	$ --	$ --

* Indicates amounts are immaterial and less than $0.1 million.

(1) The contractual obligations presented in this table reflect 100% of our subsidiaries obligations even though we own less than a 100% equity interest in our operating subsidiaries.
(2) See Note 11 for additional information regarding our credit facilities.
(3) Our estimated cash payments for interest are based on the principle amount of consolidated debt obligations outstanding at December 31, 2009. With respect to variable-rate debt, we applied the weighted-average interest rates paid during 2009. See Note 11 for information regarding variable interest rates charged in 2009 under our credit agreements. In addition, our estimate of cash payments for interest gives effect to interest rate swap agreements in place at December 31, 2009. See Note 6 for information regarding our derivative instruments.
(4) Capital expenditure commitments are reflected on a 100% basis before contributions from noncontrolling interest in connection with the Omnibus Agreement and Caverns LLC Agreement (see Note 15).

Operating lease obligations. We lease certain property, plant and equipment under noncancelable and cancelable operating leases. Amounts shown in the preceding table represent minimum cash lease payment obligations under our operating leases with terms in excess of one year.

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.

We lease the Wilson natural gas storage facility, which is integral to the operations of our Texas Intrastate System. The current term on the Wilson facility lease expires in 2028. In accordance with this lease, we have the option to purchase the Wilson facility at either December 31, 2024 for $61.0 million or January 25, 2028 for $55.0 million. In addition, the lessor, at its election, may cause us to purchase the Wilson facility for $65.0 million at the end of any calendar quarter extending through December 31, 2023.

In addition, our pipeline operations have entered into leases for land held pursuant to right-of-way agreements. Our significant right-of-way agreements have original terms that range from five to 50 years and include renewal options that could extend the agreements for up to an additional 25 years. Our rental payments are generally at fixed rates, as specified in the individual contracts, and may be subject to escalation provisions for inflation and other market-determined factors.

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. We did not make any significant leasehold improvements during the years ended December 31, 2009, 2008 or 2007. Lease expense included in costs and expenses was $9.8 million, $10.8 million and $9.9 million for the twelve months ended December 31, 2009, 2008 and 2007, respecti vely.

Purchase Obligations. We define purchase obligations as agreements to purchase goods or services that are enforceable and legally binding (unconditional) on us that specify all significant terms, including: fixed or minimum quantities to be purchased; fixed, minimum or variable price provisions; and the approximate timing of the transactions.

We have long and short-term product purchase obligations for natural gas with third-party suppliers. Our most significant product purchase obligation is a commitment that Acadian Gas has for the purchase of natural gas in Louisiana (see Note 9) that expires in January 2013. The prices that we are obligated to pay under these contracts approximate market prices at the time we take delivery of the volumes. The preceding table shows our volume commitments and estimated payment obligations under these contracts for the periods indicated. Our estimated future payment obligations are based on the contractual price at December 31, 2009 applied to all future volume commitments. Actual future payment obligations may vary depending o n market prices at the time of delivery. At December 31, 2009, we do not have any other product purchase commitments with fixed or minimum pricing provisions having remaining terms in excess of one year.

We also have short-term payment obligations relating to capital projects we have initiated. 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. The contractual obligations table shows these capital project commitments for the periods indicated.

At December 31, 2009, we had approximately $175.3 million of consolidated capital expenditure commitments outstanding. These commitments primarily relate to announced expansions of the Acadian Gas System (i.e., the Haynesville Extension) and the Texas Intrastate System (i.e., the Sherman Extension and Trinity River Lateral). Currently, we have not elected to participate in these expansion projects; therefore, EPO will fund 100% of such costs. We may elect to participate in such projects in the future. For information regarding our relationship with EPO and related project funding arrangements, see Note 15.

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 15). See Note 5 for additional information regarding accounting for equity awards.

Note 18. Significant Risks and Uncertainties

Nature of Operations in Midstream Energy Industry

Our operations are within the midstream energy industry. We are engaged in the business of: (i) NGL transportation, fractionation and marketing; (ii) storage of NGL and petrochemical products; (iii) transportation of petrochemical products; and (iv) the gathering, transportation, marketing and storage of natural gas. As such, our results of operations, cash flows and financial position may be affected by changes in the commodity prices of these hydrocarbon products, including changes in the relative price levels among these products. In general, energy commodity product prices are subject to fluctuations in response to changes in supply, market uncertainty and a variety of additional factors that are beyond our control.

Our profitability could be impacted by a decline in the volume of hydrocarbon products transported, gathered, stored or fractionated at our facilities. A material decrease in natural gas or crude oil production or crude oil refining, for reasons such as depressed commodity prices or a decrease in exploration and development activities, could result in a decline in the volume of natural gas and NGLs handled by our facilities.

A reduction in demand for NGL products by the petrochemical, refining or heating industries, whether because of: (i) general economic conditions; (ii) reduced demand by consumers for the end products made using NGLs; (iii) increased competition from petroleum-based products due to pricing differences; (iv) adverse weather conditions; (v) government regulations affecting energy commodity prices, production levels of hydrocarbons or the content of motor gasoline; or (vi) other reasons, could adversely affect our results of operations, cash flows and financial position.

Credit Risk Due to Industry Concentrations

A substantial portion of our revenues are derived from companies in the domestic natural gas, NGL and petrochemical industries. This concentration could affect our overall exposure to credit risk since these customers may be affected by similar economic or other conditions. We generally do not require collateral for our accounts receivable; however, we do attempt to negotiate offset, prepayment, or automatic debit agreements with customers that are deemed to be credit risks in order to minimize our potential exposure to any defaults.

Counterparty Risk with Respect to Derivative Instruments

In those situations where we are exposed to credit risk in our derivative instrument transactions, we analyze the counterparty's financial condition prior to entering into an agreement, establish credit and/or margin limits and monitor the appropriateness of these limits on an ongoing basis. Generally, we do not require collateral nor do we anticipate nonperformance by our counterparties.

Insurance-Related Risks

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

EPCO's deductible for onshore physical damage from windstorms is currently $25.0 million per storm. EPCO's onshore program currently provides $150.0 million per occurrence for named windstorm events. For non-windstorm events, EPCO's deductible for onshore physical damage is $5.0 million per occurrence. With respect to business interruption insurance, onshore assets must be out-of-service in excess of 60 days before any losses from business interruptions will be covered. Furthermore, pursuant to the current policy, we will now absorb 50% of the first $50.0 million of any loss in excess of deductible amounts for our onshore assets. Any amounts expensed by the DEP I and DEP II Midstream Businesses will be included in net in come and EPO's share of these losses will be attributed to noncontrolling interest.

In the third quarter of 2008, certain of our facilities located along the Gulf Coast of Texas and Louisiana were damaged by Hurricanes Gustav and Ike. As a result of our allocated share of EPCO's insurance deductibles for windstorm coverage, we expensed a combined cumulative total of $2.0 million of repair costs for property damage in connection with these two storms through December 31, 2009.

Interest Rate Risk

Our Revolving Credit Facility and Term Loan Agreement are variable rate debt obligations, which both expire in 2011. We have outstanding $175 million of variable-to-fixed interest rate swaps, all of which expire in September 2010, that partially hedge our exposure to changes in variable interest rates.

We cannot predict the costs of refinancing, at maturity, our existing credit facilities or the costs of new credit arrangements. A tight credit market, similar to the markets in late 2008 and early 2009, may have an adverse affect on our future ability to refinance our credit facilities at favorable rates or to enter into additional new credit arrangements. In addition, tight credit market conditions may translate into our having to agree to increasingly restrictive lender covenants. 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 19. Supplemental Cash Flow Information

The following table provides information regarding: (i) the net effect of changes in our operating assets and liabilities; (ii) cash payments for interest and (iii) cash payments for income taxes for the periods indicated.

	For the Year Ended December 31,		
	2009	2008	2007
Decrease (increase) in:			
Accounts receivable - trade	$ 39.6	$ 5.0	$ 9.7
Accounts receivable - related party	(9.9)	1.2	(4.2)
Gas imbalance receivables	25.9	(1.4)	28.7
Inventories	17.5	(6.0)	(6.8)
Prepaid and other current assets	(5.3)	1.6	(1.5)
Increase (decrease) in:			
Accounts payable - trade	(1.7)	(5.9)	15.8
Accounts payable - related party	(39.9)	13.5	31.0
Accrued costs and expenses	(42.7)	(10.1)	(47.7)
Accrued property taxes	0.8	1.6	1.7
Accrued taxes - other	0.1	4.8	2.7
Other current liabilities	(19.1)	6.5	(16.0)
Other long-term liabilities	(0.2)	(12.6)	0.8
Net effect of changes in operating accounts	$ (34.9)	$ (1.8)	$ 14.2
Cash payments for interest, net of $0.3, $0.3 and $2.6 capitalized in 2009, 2008 and 2007, respectively	$ 13.8	$ 11.5	$ 11.5
Cash payments for income taxes	$ 1.0	$ 0.2	$ --

We incurred liabilities for construction in progress that had not been paid at December 31, 2009, 2008 and 2007 of $41.8 million, $30.5 million and $24.8 million, respectively. Such amounts are not included under the caption “Capital expenditures” on the Statements of Consolidated Cash Flows.

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

	For the Year Ended December 31,		
	2009	2008	2007
Depreciation, amortization and accretion expense:			
DEP I Midstream Businesses	$ 38.7	$ 34.3	$ 28.9
DEP II Midstream Businesses	147.4	133.1	146.6
Duncan Energy Partners L.P. standalone	2.2	0.4	0.1
Total	$ 188.3	$ 167.8	$ 175.6

Cash payments for significant business combinations were $35.0 million for the year ended December 31, 2007. In December 2007, we acquired the South Monco natural gas pipeline business ("South Monco") from a third party for $35.0 million in cash. South Monco primarily consists of 128 miles of pipelines located in southeast Texas that gather natural gas at the wellhead for regional producers for redelivery to various points, including our Texas Intrastate System. The South Monco system includes an amine treating unit and related dehydration facilities. The South Monco transaction was accounted for using the purchase method of accounting and, accordingly, such cost has been allocated to assets acquired and liabilities assumed based on estimated fair values.

Note 20. Quarterly Financial Information (Unaudited)

The following table presents selected quarterly financial data for the years ended December 31, 2009 and 2008:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
For the Year Ended December 31, 2009:				
Revenues	$ 256.8	$ 226.7	$ 244.6	$ 251.2
Operating income	14.8	8.7	21.1	16.3
Net loss attributable to noncontrolling interest	8.9	18.7	7.0	10.7
Net income attributable to Duncan Energy Partners L.P.	19.9	23.2	24.8	23.2
Allocation of net income attributable to Duncan Energy Partners L.P.:				
Duncan Energy Partners L.P.				
Limited partners	19.8	23.0	24.6	23.1
General partner	0.1	0.2	0.2	0.1
Earnings per unit (basic and diluted)	0.34	0.40	0.43	0.40
For the Year Ended December 31, 2008:				
Revenues	363.6	478.8	432.2	323.5
Operating income	21.1	15.8	18.7	12.3
Net loss (income) attributable to noncontrolling interest	(5.6)	0.6	(4.4)	2.0
Net income attributable to Duncan Energy Partners L.P.	13.3	13.3	10.6	10.7
Allocation of net income attributable to Duncan Energy Partners L.P.:				
Duncan Energy Partners L.P.				
Limited partners	5.9	6.5	3.7	11.7
General partner	0.1	0.1	0.1	0.2
Former owner of DEP II Midstream Businesses	7.3	6.7	6.8	(1.2)
Earnings per unit (basic and diluted)	0.29	0.32	0.18	0.39

Note 21. Restatement of Certain Amounts on the Statement of Consolidated Cash Flows

Subsequent to the issuance of our 2009 financial statements, we determined that a previously disclosed related party loan to EPO (see Note 15) was incorrectly classified as an operating cash outflow rather than an investing cash outflow. As a result, cash flows provided by operating activities for the year ended December 31, 2009 were understated by $45.6 million and cash used in investing activities for the same period was understated by an equal amount. Accordingly, we have restated our operating and investing cash flows for the year ended December 31, 2009 as follows:

	Previously Reported	Restated
Operating activities:		
Net effect of changes in operating accounts (see Note 19)	$ (80.5)	$ (34.9)
Cash flows provided by operating activities	$ 156.0	$ 201.6
Investing activities:		
Other, including loans to affiliates	$ -	$ (45.6)
Cash used in investing activities	$ (383.2)	$ (428.8)

The restatement of the cash flow statement amounts noted above had no impact on our financial position or results of operations for the year ended December 31, 2009.

EXHIBIT 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in (i) Registration Statement Nos. 333-149583 and 333-163842 of Duncan Energy Partners L.P. on Form S-3; and (ii) Registration Statement No. 333-164852 of Duncan Energy Partners L.P. on Form S-8 of our report dated March 1, 2010 (May 21, 2010 as to the effects of the restatement discussed in Note 21), relating to the consolidated financial statements of Duncan Energy Partners L.P. and subsidiaries (which report expresses an unqualified opinion and includes an explanatory paragraph indicating the financial statements of the Company were prepared from the separate records maintained by Enterprise Products Partners L.P. or affiliates and may not necessarily be indicative of the conditions that would have existed or the results of operations if the Company had been operated as an unaf filiated entity), appearing in this Annual Report on Form 10-K/A of Duncan Energy Partners L.P. for the year ended December 31, 2009.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
May 21, 2010

EXHIBIT 31.1

CERTIFICATIONS

I, W. Randall Fowler, certify that:

1. I have reviewed this annual report on Form 10-K/A 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: May 21, 2010

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

EXHIBIT 31.2

CERTIFICATIONS

I, Bryan F. Bulawa, certify that:

1. I have reviewed this annual report on Form 10-K/A 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: May 21, 2010

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

EXHIBIT 32.1

SARBANES-OXLEY SECTION 906 CERTIFICATION

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

In connection with this annual report of Duncan Energy Partners L.P. (the “Registrant”) on Form 10-K/A for the year ended December 31, 2009 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: May 21, 2010

EXHIBIT 32.2

SARBANES-OXLEY SECTION 906 CERTIFICATION

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

In connection with this annual report of Duncan Energy Partners L.P. (the “Registrant”) on Form 10-K/A for the year ended December 31, 2009 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: May 21, 2010