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

FORM 10-K

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

For the fiscal year ended December 31, 2008

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, 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 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 | 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 common units of *Duncan Energy Partners L.P.* held by non-affiliates at June 30, 2008, based on the closing price of such equity securities in the daily composite list for transactions on the New York Stock Exchange, was approximately $366.2 million. This figure excludes common units beneficially owned by certain affiliates, including (i) Dan L. Duncan and (ii) Enterprise Products Operating LLC. As of March 2, 2009, there were 57,676,987 outstanding common units of Duncan Energy Partners L.P. This figure includes 42,726,987 common units owned by Enterprise Products Operating LLC, the parent company of Duncan Energy Partners L.P.

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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

This 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," "forecast," "intend," "could," "should," "will," "believe," "may," "potential" and similar expressions and statements regarding our plans and objectives for future operations, are intended to identify forward-looking statements. Although we and our general partner believe that 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 this annual report. 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.

PART I

Items 1 and 2. *Business and Properties.*

General

Duncan Energy 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 "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 ("IPO") of 14,950,000 common units and acquired controlling interests in certain midstream energy businesses of Enterprise Products Operating LLC ("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 commonly-controlled affiliates. Duncan Energy Partners is engaged in the business of (i) natural gas liquids ("NGL") transportation and fractionation; (ii) storage of NGL and petrochemical products; (iii) transportation of petrochemical products (iv) the gathering, transportation, storage of natural gas; and (v) the marketing of NGLs and natural gas.

At December 31, 2008, Duncan Energy Partners is owned 99.3% by its limited partners and 0.7% by its general partner, DEP Holdings, LLC ("DEP GP"), which is a wholly owned subsidiary of EPO. At December 31, 2008, EPO owned approximately 74% of Duncan Energy Partner's limited partner interests and 100% of its general partner. DEP GP is responsible for managing the business and operations of Duncan Energy Partners. DEP Operating Partnership L.P. ("DEP OLP"), a wholly owned subsidiary of Duncan Energy Partners, conducts substantially all of Duncan Energy Partners' business. A private company affiliate, EPCO, Inc. ("EPCO"), provides all of Duncan Energy Partners' employees and certain administrative services to the partnership.

Enterprise Products Partners conducts substantially all of its business through EPO, a wholly owned subsidiary. Enterprise Products Partners is a publicly traded partnership, the common units of which are listed on the NYSE under the ticker symbol "EPD." The general partner of Enterprise Products Partners is owned by Enterprise GP Holdings L.P. ("Enterprise GP Holdings"), a publicly traded partnership the units of which are listed on the NYSE under the ticker symbol "EPE."

One of our principal advantages is our relationship with EPO and EPCO. 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 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 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. See Item 13 of this annual report for additional information regarding our relationship with EPO and EPCO.

The following information summarizes the businesses acquired and consideration we provided in connection with the DEP I and DEP II dropdown transactions.

DEP I Dropdown Transaction

On February 5, 2007, EPO contributed a 66% controlling equity interest in each of the DEP I Midstream Businesses (defined below) to Duncan Energy Partners in a dropdown transaction (the “DEP I dropdown”) made in connection with Duncan Energy Partners’ IPO. EPO retained the remaining 34% equity interest (as a Parent Interest) in each of the DEP I Midstream Businesses. The DEP I Midstream Businesses consist of (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”).

As consideration for the equity interests in the DEP I Midstream Businesses and reimbursement for capital expenditures related to these businesses, Duncan Energy Partners distributed $260.6 million of the $290.5 million of net proceeds from its initial public offering to EPO, plus $198.9 million in borrowings under its initial credit facility (the “DEP I Revolving Credit Facility”) and a net 5,351,571 common units. Prior to the DEP I dropdown transaction, we did not have any consolidated indebtedness.

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

§ Mont Belvieu Caverns owns 33 salt dome caverns located in Mont Belvieu, Texas, with an underground NGL and petrochemical 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 gathers, transports, stores and markets natural gas in Louisiana utilizing over 1,000 miles of transmission, lateral and gathering pipelines with an aggregate throughput capacity of one billion cubic feet per day (“Bcf/d”). Acadian Gas also owns a 49.51% equity interest in Evangeline Gas Pipeline Company, L.P. (“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 Duncan Energy Partners’ Shoup and Armstrong NGL fractionation plants located in South Texas to Mont Belvieu, Texas. This pipeline commenced operations in January 2007.

DEP II Dropdown Transaction

On December 8, 2008, Duncan Energy Partners entered into a Purchase and Sale Agreement (the “DEP II Purchase Agreement”) with EPO and Enterprise GTM Holdings L.P. (“Enterprise GTM,” a wholly owned subsidiary of EPO). Pursuant to the DEP II Purchase Agreement, DEP OLP acquired 100% of the membership interests in Enterprise Holding III, LLC (“Enterprise III”) from Enterprise GTM, thereby acquiring a 66% general partner interest in Enterprise GC, L.P. (“Enterprise GC”), a 51% general partner interest in Enterprise Intrastate L.P. (“Enterprise Intrastate”) and a 51% membership interest in Enterprise

Texas Pipeline LLC ("Enterprise Texas"). Collectively, we refer to Enterprise GC, Enterprise Intrastate and Enterprise Texas as the "DEP II Midstream Businesses." As with the DEP I dropdown, EPO was also the sponsor of this second dropdown transaction (the "DEP II dropdown"). Enterprise GTM retained the remaining partner and member interests (as a Parent Interest) in the DEP II Midstream Businesses.

As consideration for the Enterprise III membership interests, EPO received $280.5 million in cash and 37,333,887 Class B limited partner units having, at the time of issuance, a market value of $449.5 million from Duncan Energy Partners. The total value of the consideration provided to EPO and Enterprise GTM was $730.0 million. The cash portion of the consideration provided by Duncan Energy Partners in this dropdown transaction was derived from borrowings under a new bank term loan agreement (the "DEP II Term Loan Agreement") and the proceeds of a $0.5 million equity offering to EPO. On February 9, 2009, the Class B units received a prorated cash distribution of $0.1115 per unit for the distribution that Duncan Energy Partners paid with respect to the fourth quarter of 2008 for the 24-day period from December 8, 2008, the closing date of the DEP II dropdown transaction, to December 31, 2008. On February 1, 2009, the Class B units automatically converted on a one-for-one basis to common units.

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

§ Enterprise GC owns (i) the Shoup and Armstrong NGL fractionation facilities located in South Texas, (ii) a 1,020-mile NGL pipeline system located in South Texas and (iii) 944 miles of natural gas gathering pipelines located in South and West Texas. Enterprise GC's natural gas gathering pipelines include (i) the 272-mile Big Thicket Gathering System located in Southeast Texas, (ii) the 465-mile Waha system located in the Permian Basin of West Texas and (iii) the 207-mile TPC gathering system.

§ 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 6,547-mile Enterprise Texas natural gas pipeline system and leases the Wilson natural gas storage facility. The Enterprise Texas system, along with the Waha, TPC and Channel pipeline systems, comprise the Texas Intrastate System.

Generally, 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 Enterprise III (based on an initial defined investment of $730.0 million) and then to Enterprise GTM (based on an initial defined investment of $452.1 million) in amounts sufficient to generate an aggregate initial annualized return on their respective investments of 11.85%. Distributions in excess of these amounts will be distributed 98% to Enterprise GTM and 2% to Enterprise III. Income and loss of the DEP II Midstream Businesses are first allocated to Enterprise III and Enterprise GTM 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.

For information regarding EPO's Parent Interest in the DEP I and DEP II Midstream Businesses, see "Parent Interest in Subsidiaries" within this Item 7. See Item 13 of this annual report for additional information regarding our ongoing and extensive relationship with EPO, including certain contractual arrangements entered into as a result of the DEP I and DEP II dropdown transactions.

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 dropdown 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 dropdown transactions were 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 IPO, or February 5, 2007 (February 1, 2007 for financial accounting and reporting purposes).

References to the "former owners" of the DEP I and DEP II Midstream Businesses primarily refer to the direct and indirect ownership by EPO in these businesses prior to the related dropdown transactions. References to "Duncan Energy Partners" mean the registrant since February 5, 2007 and its consolidated subsidiaries. Generic references to "we," "us" and "our" mean the combined and/or consolidated businesses included in these financial statements for each reporting period.

Our consolidated financial statements include the accounts of Duncan Energy Partners, and prior to the DEP I and DEP II dropdown transactions, the assets, liabilities and operations contributed to us by EPO upon the closing of these dropdown 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 transactions 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, 2006 reflect the combined financial information of the DEP I and DEP II Midstream Businesses on a 100% basis. The results of operations and cash flows for these businesses 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, 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 dropdown 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 dropdown transaction is February 1, 2007. EPO's retained ownership in the DEP I Midstream Businesses (following the dropdown transaction) is presented in our consolidated financial statements as "Parent interest in Subsidiaries – DEP I Midstream Businesses."

§ 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 dropdown transaction. On December 8, 2008, the DEP II Midstream Businesses were contributed to Duncan Energy

Partners in the DEP II dropdown 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 dropdown transaction) is presented in our consolidated financial statements as "Parent interest in Subsidiaries – DEP II Midstream Businesses."

Effective with the fourth quarter of 2008, our segment information was restated for all periods in connection with the DEP II dropdown transaction.

Business Strategy

Our primary business objectives are to maintain and, over time, to increase our cash available for distributions to our unitholders. Our business strategies to achieve these objectives are to:

§ optimize the benefits of our economies of scale, strategic location and pipeline connections serving our natural gas, NGL, petrochemical and refining markets;

§ manage our portfolio of midstream energy assets to minimize the volatility of our cash flows;

§ invest in organic growth projects to capitalize on market opportunities that expand our asset base and generate additional cash flow; and

§ pursue acquisitions of assets and businesses from related parties, or in accordance with our business opportunity agreements, from third parties.

Segment Discussion

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. Effective with the fourth quarter of 2008, our segment information has been recast as a result of the DEP II dropdown transaction.

A related party, Evangeline, is our largest customer and accounted for 22.7%, 21.7% and 22.0% of our consolidated revenues in 2008, 2007 and 2006, respectively. Related party revenues from Evangeline are attributable to the sale of natural gas and are presented in our Natural Gas Pipelines & Services business segment. Sales to Evangeline totaled $362.9 million, $264.2 million and $277.7 million for the years ended December 31, 2008, 2007 and 2006, respectively.

For the year ended December 31, 2008, our largest third party customer was Exxon Mobil Corporation ("Exxon Mobil") and its affiliates, which accounted for approximately 10.0% of our consolidated revenues. Exxon Mobil accounted for 7.6% and 7.3% of our consolidated revenues in 2007 and 2006, respectively. The majority of our revenues from Exxon Mobil are derived from the sale and transportation of natural gas and are also presented in our Natural Gas Pipelines & Services business segment. Sales to Exxon Mobil totaled $159.2 million, $93.2 million and $92.0 million for the years ended December 31, 2008, 2007 and 2006, respectively.

Our business activities are subject to various federal, state and local laws and regulations governing a wide variety of topics, including commercial, operational, environmental, safety and other matters. For a discussion of the principal effects such laws and regulations have on our business, see "Regulation" and "Environmental and Safety Matters" included within this Item 1.

Our results of operations and financial condition are subject to a variety of risks. For information regarding our key risk factors, see Item 1A of this annual report.

For information regarding our results of operations, including historical operating rates, see Item 7 of this annual report.

For financial information regarding our business segments, see Note 13 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

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

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

Natural Gas Pipelines & Services

Our Natural Gas Pipelines & Services business segment includes approximately 9,174 miles of natural gas gathering and transmission pipeline systems in Texas and Louisiana. We also lease natural gas storage facilities located in Texas and Louisiana that are integral components of these systems. This segment includes our natural gas marketing activities related to the Acadian Gas System.

The following table summarizes the significant assets included in our Natural Gas Pipelines & Services business segment at February 2, 2009:

Description of Asset	Location	Length (Miles)	Approx. Net Capacity, Natural Gas (MMcf/d)	Working Capacity (Bcf)
Natural gas pipelines:				
Texas Intrastate System	Texas	7,860	5,535	
Acadian Gas System	Louisiana	1,042	1,149	
Big Thicket Gathering System (1)	Texas	272	80	
Total miles		9,174		
Natural gas storage facilities:				
Wilson	Texas			6.8
Acadian	Louisiana			1.7
Total gross capacity				8.5

(1) The Big Thicket Gathering System is an integral part of our NGL marketing activities, the results of operations of which are accounted for under our NGL Pipelines & Services business segment.

Our natural gas pipelines gather and transport natural gas from onshore developments, such as the Barnett Shale and Permian supply basins in Texas, and from offshore developments in the Gulf of Mexico through connections with offshore pipelines. Typically, these systems receive natural gas from producers, other pipelines or shippers through system interconnects and redeliver the natural gas to processing facilities, local gas distribution companies, industrial or municipal customers or other onshore pipelines. We lease underground salt dome natural gas storage caverns that are integral components of our Texas Intrastate and Acadian Gas Systems. These caverns can handle high levels of injections and withdrawals of natural gas, which is beneficial in meeting demand swings and covering major supply interruption events, such as hurricanes and temporary losses of production.

Our natural gas pipelines generate revenues from transportation agreements where shippers are billed a fee per unit of volume transported (typically in MMBtus) multiplied by the volume delivered. The transportation fees charged under these arrangements are either contractual or regulated by governmental agencies. Our natural gas pipelines, particularly the Texas Intrastate System, also offer firm capacity reservation services whereby the shipper pays a contractually stated fee based on the level of capacity reserved by such shipper in our pipelines whether or not the reserved quantity of natural gas is actually shipped. Revenues from firm natural gas storage contracts typically have two components: (i) a monthly demand payment, which is associated with storage capacity reservations; and (ii) a fuel-based fee per unit of volume injected at each location.

Our Acadian Gas System purchases natural gas from producers and suppliers and resells such natural gas to customers such as electric utility companies, local natural gas distribution companies and industrial customers. Our natural gas marketing activities generate revenues from the sale and delivery of natural gas obtained primarily from (i) third party well-head purchases, (ii) EPO's natural gas processing plants and (iii) the open market. In general, our natural gas sales contracts utilize market-based pricing and can incorporate pricing differentials for factors such as delivery location.

We are exposed to commodity price risk to the extent that we take title to natural gas volumes through our natural gas marketing activities or through certain contracts on our intrastate natural gas pipelines. In addition, certain segments of our Texas Intrastate System (i.e., the Waha gathering system) provide aggregating and bundling services, in which we purchase and resell natural gas for certain small producers. We use commodity financial instruments from time to time to mitigate our exposure to risks related to commodity prices. For information regarding our use of commodity financial instruments, see Item 7A of this annual report.

On a weighted-average basis, aggregate utilization rates for our natural gas pipelines were approximately 68.3%, 63.3% and 69.0% during the years ended December 31, 2008, 2007 and 2006, respectively. The following table presents average pipeline throughput volumes (in BBtus/d) for the periods indicated:

	For the Year Ended December 31,		
	2008	**2007**	**2006**
Natural gas transportation volumes:			
Texas Intrastate System	4,021	3,550	3,586
Acadian Gas System	378	416	434
Total transportation volumes	4,399	3,966	4,020
Natural gas sales volumes:			
Acadian Gas System	331	308	325
Total natural gas throughput volumes	4,730	4,274	4,345

The following information highlights the general use of each of our principal natural gas pipelines, all of which we operate except for small segments of the Texas Intrastate System.

- The *Texas Intrastate System* gathers and transports natural gas from supply basins in Texas (from both onshore and offshore sources) to local gas distribution companies and electric generation and industrial and municipal consumers as well as to connections with intrastate and interstate pipelines. The Texas Intrastate System is comprised of the 6,547-mile Enterprise Texas pipeline system, the 641-mile Channel pipeline system, the 465-mile Waha gathering system and the 207-mile TPC gathering system. The Enterprise Texas pipeline system includes a 263-mile pipeline we lease from an affiliate of Energy Transfer Partners, L.P. The leased Wilson natural gas storage facility, located in Wharton County, Texas, is an integral part of the Texas Intrastate System. The Wilson facility has a net useable storage capacity of 6.8 Bcf. Collectively, the Texas Intrastate System serves important natural gas producing regions and commercial markets in Texas, including Corpus Christi, the San Antonio/Austin area, the Beaumont/Orange area and the Houston area, including the Houston Ship Channel industrial market.

  Portions of the 178-mile Sherman Extension of our Texas Intrastate System were placed in-service during 2008, with the remainder scheduled for final completion in March 2009. The Sherman Extension is capable of transporting up to 1.1 Bcf/d of natural gas from the prolific Barnett Shale production basin in North Texas and provides producers with interconnects with third party interstate pipelines having access to markets outside of Texas. Customers, including EPO, have contracted for an aggregate 1.0 Bcf/d of the capacity of the Sherman Extension.

In late 2008, we began design of the 40-mile Trinity River Basin Extension, which is expected to be completed in the fourth quarter of 2009. The Trinity River Basin Extension will be capable of transporting up to 1.0 Bcf/d of natural gas and will provide producers in the Barnett Shale production basin with additional takeaway capacity. We are also constructing a new storage cavern adjacent to the leased Wilson natural gas storage facility that is expected to be completed in 2010. When completed, this new cavern is expected to provide us with an additional 5.0 Bcf of useable natural gas storage capacity.

As a result of the DEP II dropdown transaction, we own a 51% equity interest in the entity that owns the Enterprise Texas and Channel pipeline systems and leases the Wilson storage facility. In addition, we own a 66% equity interest in the entity that owns the Waha and TPC gathering systems. EPO owns the remaining equity interests in these entities.

§ The *Acadian Gas System* purchases, transports, stores and sells natural gas in Louisiana. The Acadian Gas System is comprised of the 577-mile Cypress pipeline, the 438-mile Acadian pipeline and the 27-mile Evangeline pipeline. The leased Acadian natural gas storage facility is an integral part of the Acadian Gas System. The Acadian Gas pipeline system links natural gas supplies from onshore Gulf Coast and offshore Gulf of Mexico developments with local gas distribution companies, electric generation plants and industrial customers, located primarily in the natural gas market area of the Baton Rouge – New Orleans – Mississippi River corridor.

As a result of the DEP I dropdown transaction, we own a 66% equity interest in the entities that own the Acadian Gas System, including Acadian Gas' 49.51% interest in Evangeline pipeline, discussed below.

Evangeline is our largest customer and accounted for 22.7% of our consolidated revenues in 2008. Acadian Gas does not have a controlling interest in Evangeline, but does exercise significant influence over its operating policies. Evangeline's most significant contract is a natural gas sales agreement with Entergy Louisiana ("Entergy") that expires in January 2013. Under this contract, 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 of natural gas.

In connection with the Entergy sales contract, Evangeline has entered into a natural gas purchase contract with 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 monthly weighted-average market price of natural gas (subject to certain market index price ceilings and incentive margins) plus a predetermined margin. Acadian Gas sold $362.9 million, $264.2 million and $277.7 million of natural gas to Evangeline during the years ended December 31, 2008, 2007 and 2006, respectively. The amount of natural gas purchased by Evangeline pursuant to this contract was 36.9 BBtus during the year ended December 31, 2008 and 36.8 BBtus during each of the years ended December 31, 2007 and 2006.

Typically, our natural gas pipelines experience higher throughput rates during the summer months as natural gas-fired power generation facilities increase output to meet residential and commercial demand for electricity for air conditioning. Higher throughput rates are also experienced in the winter months as natural gas is needed to fuel residential and commercial heating. Likewise, this seasonality also impacts the timing of injections and withdrawals at our natural gas storage facilities.

Within their market areas, our natural gas pipelines compete with other pipelines on the basis of price (in terms of transportation fees or natural gas selling prices), location, connectivity, service, reliability and flexibility. We believe that the transportation fees and natural gas sales prices we charge are competitive with those charged by other pipeline and gas marketing companies because most prices in this business are based on published indices. We also believe that our competitive position is enhanced due to a number of long-standing customer relationships due, in part, to a limited number of alternative delivery pipeline connections. Although our competitors could connect their systems to our customers, the construction costs involved would typically be prohibitive. Lastly, we believe that our emphasis on maintenance and safety provides our customers with confidence in our operational dependability and flexibility in meeting their natural gas requirements.

Our Wilson natural gas storage facility competes with storage service providers such as Enstor Inc. and Tres Palacios Gas Storage LLC. The key competitive elements of storage services are price, service, capacity, connectivity and customer relationships.

NGL Pipelines & Services

Our NGL Pipelines & Services business segment includes our NGL and petrochemical storage facility located in Mont Belvieu, Texas and our South Texas NGL System that connects our Mont Belvieu storage complex to midstream energy infrastructure located in South Texas. In addition, this segment includes the results of our NGL marketing activities related to our Big Thicket Gathering System. The South Texas NGL System consists of: (i) two NGL fractionation facilities (i.e., the Shoup and Armstrong plants); (ii) approximately 380 miles of intrastate NGL transportation pipelines that link various South Texas natural gas processing facilities (primarily those owned by EPO) to the Shoup and Armstrong plants and other customers; and (iii) two intrastate NGL pipelines aggregating approximately 937 miles that deliver NGLs from our south Texas fractionation facilities to refineries and petrochemical plants located between Corpus Christi and Houston, Texas and within the Texas City-Houston area, as well as to common carrier NGL pipelines and product storage facilities including our Mont Belvieu storage complex. We also lease two NGL storage facilities that are integral components of the South Texas NGL System.

NGL products (ethane, propane, normal butane, isobutane and natural gasoline) are used as raw materials by the petrochemical industry, as feedstocks by refiners in the production of motor gasoline and by industrial and residential users as fuel. Ethane is primarily used in the petrochemical industry as a feedstock for ethylene production, one of the basic building blocks for a wide range of plastics and other chemical products. Propane is used both as a petrochemical feedstock in the production of ethylene and propylene and as a heating, engine and industrial fuel. Normal butane is used as a petrochemical feedstock in the production of ethylene and butadiene (a key ingredient of synthetic rubber), as a blendstock for motor gasoline and to derive isobutane through isomerization. Isobutane is fractionated from mixed butane (a mixed stream of normal butane and isobutane) or produced from normal butane through the process of isomerization, principally for use in refinery alkylation to enhance the octane content of motor gasoline, in the production of isooctane and other octane additives, and in the production of propylene oxide. Natural gasoline, a mixture of pentanes and heavier hydrocarbons, is primarily used as a blendstock for motor gasoline or as a petrochemical feedstock.

The following table summarizes the significant assets included in our NGL Pipelines & Services business segment at December 31, 2008:

Description of Asset	Location	Length (Miles)	Useable Storage Capacity (MMBbls)	Total Plant Capacity (MBPD)
NGL pipelines:				
South Texas NGL System	Texas	1,317		
NGL and petrochemical storage facilities:				
Mont Belvieu Storage (33 caverns) (1)	Texas		103.5	
Almeda (6 caverns) (1, 2)	Texas		13.4	
Markham (2 caverns) (1, 2)	Texas		4.3	
Total useable capacity			121.2	
NGL fractionation facilities:				
Shoup (2)	Texas			69
Armstrong (2)	Texas			18
Total plant capacities				87

(1) The Mont Belvieu storage complex includes above-ground brine pit capacity of 20 MMBbls. Brine capacity at the Almeda and Markham facilities is limited to the quantity necessary to support the product storage operations.

(2) These assets are an integral part of the South Texas NGL System.

Our NGL pipelines (i) transport mixed NGLs from natural gas processing facilities and refineries to NGL fractionation plants and storage facilities and (ii) distribute to, and collect purity NGL products from, petrochemical plants and refineries. Revenues from our NGL pipeline transportation agreements are generally based upon a fixed fee per gallon of liquids transported multiplied by the volume delivered. Accordingly, the results of operations for this business are generally dependent upon the volume of product transported and the level of fees charged to customers. The transportation fees charged under these arrangements are contractual and not typically regulated by governmental agencies. Typically, we do not take title to the products transported in our NGL pipelines; rather, the shipper retains title and the associated commodity price risk.

Our NGL and petrochemical storage facilities receive, store and deliver NGLs and petrochemical products for industrial customers located along the Texas Gulf Coast. This area has the largest concentration of petrochemical plants and refineries in the United States. Our NGL and petrochemical storage facilities are interconnected by multiple pipelines to other producing and offtake facilities throughout the Gulf Coast region, including EPO’s NGL import/export facility located on the Houston Ship Channel, as well as connections to the Rocky Mountain and Midwest regions via EPO’s Seminole pipeline and to Louisiana via EPO’s Lou-Tex NGL pipeline.

We also store certain petrochemicals such as propylene (chemical, polymer and refinery grades) and ethylene. Chemical-grade propylene is a petrochemical used in plastics, synthetic fibers and foams. Polymer-grade propylene is primarily used in the manufacture of polypropylene, which has a variety of end uses, including packaging film, carpet and upholstery fibers and plastic parts for appliances, automobiles and medical devices. Refinery grade propylene is produced by refineries and is used as a feedstock in the production of polymer-grade and chemical-grade propylene. Ethylene is also a key building block for the petrochemical industry. Ethylene derivatives are used in film applications for packaging, carrier bags and trash liners. Other applications include injection molding, pipe extrusion and cable sheathing and insulation, as well as extrusion coating of paper and cardboard.

Under our NGL and petrochemical storage agreements, we charge customers monthly storage reservation fees to reserve storage capacity in our underground caverns. Our customers pay reservation fees based on the capacity reserved rather than the actual capacity utilized. When a customer exceeds its reserved capacity, we charge those customers an excess storage fee. In addition, we charge our customers throughput fees based on volumes injected and withdrawn from the storage facility. Lastly, brine production revenues are derived from customers that use brine in the production of chlorine and caustic soda, which is used in the production of polyvinyl chloride (“PVC”) and for industrial products used in crude oil production and fractionation. Brine is produced by injecting fresh water into a well to create cavern space within the salt dome. This process enables brine to be produced for our customers, as well as for developing new underground wells for product storage. Accordingly, the profitability of our storage operations is dependent upon the level of capacity reserved by our customers, the volume of product injected and withdrawn from our underground caverns, the level of fees charged and the volume of brine produced for our customers.

We have a broad range of customers for our storage services with contract terms that vary from month-to-month to long-term contracts with durations of one to ten years. We currently offer our customers, in various quantities and at varying terms, two main types of storage contracts: multi-product fungible storage and segregated product storage. Multi-product fungible storage allows customers to store any combination of fungible products. Segregated product storage allows customers to store non-fungible products such as propylene, ethylene and naphtha. Segregated storage allows a customer to reserve an entire storage cavern and have its own product injected and withdrawn without having its product commingled. We evaluate pricing, volume and availability for storage on a case-by-case basis.

Our Shoup and Armstrong NGL fractionation facilities separate mixed NGL streams originating from South Texas production basins into purity NGL products.   Based on industry data, we believe that there will be sufficient quantities of natural gas in South Texas to support the production of mixed NGLs for the next twenty to forty years. For example, new sources of rich gas may exist in the Cretaceous sands of southwest Texas and the Oligocene Vicksburg formations below 14,000 feet in South Texas. In the mid-Gulf Coast region, rich Wilcox gas is found at depths in the 10,000 to 15,000 feet range. Shale gas in these areas may also have high NGL content. We expect that ongoing natural gas exploration and production activities will result in new volumes that will mitigate the effects of normal depletion rates of existing resource basins.

The following table presents significant average throughput and processing volumetric data for the NGL Pipelines & Services segment for the periods indicated:

	For the Year Ended December 31,		
	2008	**2007**	**2006**
NGL transportation volumes: (1)			
South Texas NGL System (MBPD)	126	124	57
NGL fractionation volumes: (2)			
Shoup and Armstrong plants (MBPD)	80	72	66

(1) The maximum number of barrels that our NGL pipelines can transport per day depends upon the operating balance achieved at a given point in time between various segments of the system. Since the operating balance is dependent upon the mix of products to be shipped and demand levels at various delivery points, the exact capacity of our NGL pipelines cannot be determined. We measure the utilization rates of our NGL pipelines in terms of average throughput.

(2) On a weighted-average basis, aggregate utilization rates for our NGL fractionation plants were approximately 84.3%, 82.8% and 76.7% during the years ended December 31, 2008, 2007 and 2006, respectively.

The following information highlights the general use of each of our principal NGL pipeline, storage and fractionation assets, all of which we operate except for the leased Markham and Almeda NGL storage facilities.

§ The *South Texas NGL System* consists of: (i) two NGL fractionation facilities (i.e., the Shoup and Armstrong plants); (ii) approximately 380 miles of intrastate NGL transportation pipelines that transport mixed NGLs from various South Texas natural gas processing facilities (primarily those owned by EPO) to our Shoup and Armstrong fractionators; and (iii) intrastate NGL pipelines aggregating 937 miles that deliver NGLs from the Shoup and Armstrong fractionators to our Mont Belvieu storage complex and to other customers along the upper Texas Gulf Coast. We also lease two NGL storage facilities (i.e., Markham and Almeda) that are integral components of the South Texas NGL System.

The South Texas NGL System includes a 297-mile pipeline system (the DEP South Texas NGL pipeline) that we acquired in connection with the DEP I dropdown transaction. This component of the South Texas NGL System became operational in January 2007. The remainder of the South Texas NGL System was acquired in connection with the DEP II dropdown transaction.

The Shoup NGL fractionator is located in Corpus Christi, Texas and receives mixed NGLs from six natural gas processing plants located in South Texas. The Armstrong NGL fractionator is located in Dewitt County, Texas and fractionates mixed NGLs for EPO's Armstrong natural gas processing plant.

A major customer of our South Texas NGL System is EPO, which uses the system to process, transport and store NGLs. EPO accounted for 90% of the revenues generated by the South Texas NGL System during the year ended December 31, 2008.

As a result of the DEP I and DEP II dropdown transactions, we own a 66% equity interest in the entities that own the assets comprising the South Texas NGL System. EPO owns the remaining equity interests in these entities.

§ The *Mont Belvieu Storage* complex consists of three interconnected underground storage facilities: Mont Belvieu East, Mont Belvieu West and Mont Belvieu North. The Mont Belvieu East facility is the largest of our three Mont Belvieu storage facilities. This facility consists of 13 storage caverns with an underground NGL and petrochemical storage capacity of approximately 55 MMBbls and an above-ground brine pit with a brine capacity of approximately 10 MMBbls. This facility also has two brine production wells. The Mont Belvieu West facility consists of 10 caverns with an underground NGL and petrochemical storage capacity of approximately 15 MMBbls and an above-ground brine pit with a brine capacity of approximately 2 MMBbls. The Mont Belvieu North facility consists of 10 caverns with an underground NGL and petrochemical storage capacity of approximately 30 MMBbls and an above-ground brine pit with a brine capacity of approximately 8 MMBbls.

We have initiated several projects to improve the integration of our three Mont Belvieu storage facilities. These projects include additional pipelines to more efficiently connect the facilities and the drilling of additional entry points into certain wells to increase flow rates.

Our storage customers include a broad range of NGL and petrochemical producers and consumers, including many of the largest petrochemical facilities and refineries along the Texas and Louisiana Gulf Coast region. Our three largest third-party storage customers, which accounted for 33% of our segment revenues for the year ended December 31, 2008, were affiliates of the Dow Chemical Company, Exxon Mobil and Shell Oil Company.

We also provide underground storage services to EPO, which accounted for 38% of our Mont Belvieu storage revenues for the year ended December 31, 2008. As a result of contracts executed in connection with our IPO, we increased certain storage fees charged to EPO for use of the facilities owned by Mont Belvieu Caverns to market-based rates. Historically, such intercompany charges were below market.

As a result of the DEP I dropdown transaction, we own a 66% equity interest Mont Belvieu Caverns. EPO owns the remaining equity interests in this entity.

Storage well measurement gains and losses occur when product movements into a storage well are different than those redelivered to customers. In connection with storage agreements entered into between EPO and Mont Belvieu Caverns effective concurrently with the closing of our IPO, EPO agreed to assume all storage well 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. Beginning February 2007, the Mont Belvieu Caverns' limited liability company agreement allocates to EPO any items of income or loss relating to net operational measurement gains and losses, including amounts that Mont Belvieu Caverns may retain as handling losses. As such, 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 as a component of operating costs and expenses. However, these operational measurement gains and losses should not affect our net income or have a significant impact on us with respect to the timing of our net cash flows provided by operating activities and, accordingly, we have not established a reserve for operational measurement losses on our balance sheet. We recognized net operational measurement losses of $6.8 million and net operational measurement gains of $4.5 million for the years ended December 31, 2008 and 2007, respectively, which were allocated to EPO as our Parent.

Our NGL pipelines and fractionation assets exhibit little to no seasonal variation in operations. We operate our NGL and petrochemical storage facilities based on the needs and requirements of our customers in the NGL, petrochemical, heating and other related industries. We usually experience an increase in the demand for storage services during the spring and summer months due to increased feedstock storage requirements for motor gasoline production and a decrease during the fall and winter months when propane inventories are being drawn for heating needs.

The pipeline and fractionation operations included in our South Texas NGL System are not affected by competition given that EPO is the primary customer of these businesses.

Our competitors in the NGL and petrochemical storage business are integrated major oil companies, chemical companies and other storage and pipeline companies. With respect to our Mont Belvieu underground storage complex, we primarily compete against LDH Energy Mont Belvieu L.P., Targa Resources, Inc. and ONEOK Partners, L.P. We compete with other storage service providers primarily in terms of the fees charged, number of pipeline connections and operational dependability. We believe that the fees we charge our storage customers are competitive with those charged by other storage operators because we have historically been able to renew existing contracts as they mature, which has resulted in many long-standing customer relationships. We also believe that the number of pipelines connected to our storage facilities allows us to offer customers a wider variety of receipt and delivery options with respect to key Gulf Coast petrochemical plants, NGL fractionators and other users of the products we store. Furthermore, we believe that our emphasis on maintenance and safety provides our customers with a high level of confidence in our operational dependability.

Petrochemical Services

Our Petrochemical Services business segment reflects the operations of our Lou-Tex Propylene Pipeline and Sabine Propylene Pipeline systems. These systems provide for the transportation of polymer-grade and chemical-grade propylene in Texas and Louisiana. Polymer-grade propylene is used in the manufacture of polypropylene. Chemical-grade propylene is a basic petrochemical used in plastics, synthetic fibers and foams.

The following information highlights the general use of each of our principal petrochemical pipelines, both of which we operate:

§ The *Lou-Tex Propylene Pipeline* is a 263-mile pipeline used to transport chemical-grade propylene from Sorrento, Louisiana to Mont Belvieu, Texas. Shell and Exxon Mobil are the only customers of this pipeline. The chemical-grade propylene we transport for Shell originates at its underground storage facility located in Sorrento, Louisiana and is delivered to various receipt points between Sorrento, Louisiana and Mont Belvieu, Texas. The receipt points on the Lou-Tex Propylene Pipeline include connections with Vulcan, Westlake Lake Charles, Beaumont Novus, and Shell's Texas chemical-grade propylene delivery system. The chemical-grade propylene we transport for Exxon Mobil originates from its refining and chemical complex located in Baton Rouge, Louisiana and is delivered to either Exxon Mobil's customers or to an underground storage well located in Mont Belvieu, Texas owned by Mont Belvieu Caverns.

§ The *Sabine Propylene Pipeline* consists of a 21-mile pipeline used to transport polymer-grade propylene from Port Arthur, Texas to an interconnect with EPO's Lake Charles propylene pipeline in Cameron Parish, Louisiana. Shell is the sole customer of this pipeline. The polymer-grade propylene transported for Shell originates from the TOTAL/BASF Port Arthur cracker facility and is delivered to the Lyondell Basell polypropylene facility in Lake Charles, Louisiana.

As a result of the DEP I dropdown transaction, we own a 66% equity interest in Lou-Tex Propylene and Sabine Propylene. EPO owns the remaining equity interests in these entities.

Revenues recorded for the Lou-Tex Propylene Pipeline and Sabine Propylene Pipeline are primarily based on exchange agreements with Shell and 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. The following information summarizes the exchange agreements with Shell and Exxon Mobil:

§ Shell Exchange Agreements – Shell is obligated to meet minimum delivery requirements under the Lou-Tex Propylene and Sabine Propylene agreements. If Shell fails to meet such minimum delivery requirements, it is obligated to pay a deficiency fee to us. The term of the Lou-Tex Propylene exchange agreement expires in March 2020 and the term of the Sabine Propylene exchange agreement expires in November 2011; however, both agreements will continue on an annual basis after expiration, subject to termination by either party. The fees paid by Shell under the Lou-Tex Propylene exchange agreement are generally fixed. The fees paid by Shell under the Sabine Propylene exchange agreement are adjusted annually based on the operating costs of the pipeline and the U.S. Department of Labor wage index.

§ Exxon Mobil Exchange Agreement – The term of the Lou-Tex Propylene Pipeline exchange agreement expired in June 2008, but continues on a monthly basis subject to a two-year termination notice initiated by either party. The exchange fees paid by Exxon Mobil are based on the volume of chemical-grade propylene delivered.

For those periods prior to February 5, 2007, EPO was the shipper of record on these pipeline systems and billed Shell and Exxon Mobil for actual amounts due under the exchange agreements. In turn, Lou-Tex Propylene and Sabine Propylene billed EPO the full tariff rate, which was in excess of the amounts EPO billed Shell and Exxon Mobil under the exchange agreements. Effective February 1, 2007, EPO assigned the exchange agreements to us and Lou-Tex Propylene and Sabine Propylene started billing Shell and Exxon Mobil for amounts due under the exchange agreements.

On a weighted-average basis, aggregate utilization rates for our petrochemical pipelines were approximately 48%, 51% and 51% during the years ended December 31, 2008, 2007 and 2006, respectively. The following table presents average pipeline throughput volumes (in MBPD) for the periods indicated:

	For the Year Ended December 31,		
	2008	**2007**	**2006**
Lou-Tex Propylene Pipeline (1)	25	25	27
Sabine Propylene Pipeline (1)	10	12	10
Total petrochemical throughput volumes	35	37	37

(1) The maximum number of barrels that our petrochemical pipelines can transport per day depends upon the operating balance achieved at a given point in time between various segments of the system. Since the operating balance is dependent upon the demand levels at various delivery points, the exact capacity of our petrochemical pipelines cannot be determined. We measure the utilization rates of our petrochemical pipelines in terms of average throughput.

Our propylene transportation business exhibits little seasonality. With respect to competition, our petrochemical pipelines are in single product service due to the required purity of the product being shipped. Because there are no other pipelines in our market area which ship the same dedicated purity-grade product, competition for this service is limited. In the future, a competitor could change service of an existing pipeline to ship such purity products, but it would incur additional costs to connect their systems to our customers.

Title to Properties

Our real property holdings fall into two basic categories: (1) parcels that we own in fee, such as the land and underlying storage caverns at Mont Belvieu, Texas and (2) parcels in which our interest derives from leases, easements, rights-of-way, permits or licenses from landowners or governmental authorities permitting the use of such land for our operations. The fee sites upon which our major facilities are located have been owned by us or our predecessors in title for many years without any material challenge known to us relating to title to the land upon which the assets are located, and we believe that we have satisfactory title to such fee sites. We have no knowledge of any challenge to the underlying fee title of any material lease, easement, right-of-way or license held by us or to our title to any material lease, easement, right-of-way, permit or license.   We believe that we have satisfactory title to all of our material leases, easements, rights-of-way and licenses.

Capital Spending

For a discussion of our capital spending program, see "Liquidity and Capital Resources" included under Item 7 of this annual report.

Regulation

Regulation of Our Intrastate Natural Gas Pipelines and Storage Services

The majority of the intrastate natural gas pipelines in the Acadian Gas System are subject to various Louisiana state laws and regulations that affect the rates they charge and the terms of service for intrastate services. Our Texas intrastate pipelines are subject to various Texas state laws and regulations that may affect the rates they charge and the terms of service for intrastate services.

Our natural gas intrastate systems also provide transportation and storage pursuant to Section 311 of the NGPA and Part 284 of the FERC's regulations. Under Section 311 of the NGPA, an intrastate pipeline company may transport gas for an interstate pipeline company or any local distribution company served by an interstate pipeline without becoming subject to the full jurisdictional authority of the FERC. However, such a pipeline is required to provide these services on an open and nondiscriminatory basis, and to make certain rate and other filings and reports in compliance with the FERC's regulations. The rates for Section 311 service can be established by the FERC or the respective state agency. If established by the FERC, the rates may not exceed a fair and equitable rate and are subject to challenge. Unless the FERC grants specific authority to charge market-based rates, our rates are derived based on a cost-of-service methodology.

In December 2006, the FERC approved an uncontested settlement that established our maximum interruptible transportation rates for Section 311 service on the Acadian and Cypress pipelines. We are required to file another rate petition on or before July 11, 2009 to justify our current rates or establish new rates for NGPA Section 311 service. The Louisiana Public Service Commission also reviews and approves rates for pipelines providing intrastate service in Louisiana. For example, the Louisiana Public Service Commission regulates Acadian Gas' city gate sales. We also have a natural gas underground storage facility in Louisiana that is subject to state regulation.

In September 2007, the FERC approved an uncontested settlement establishing our maximum firm and interruptible transportation rates for NGPA Section 311 service on the Enterprise Texas Pipeline. In September 2008, we submitted to FERC a new proposed Section 311 rate for service on our Sherman

Extension pipeline, which rate is presently under review by FERC. We are required to file another rate petition on or before April 2010 to justify our current system-wide rates or establish new system-wide rates for NGPA Section 311 service. The Texas Railroad Commission (“TRRC”) has the authority to regulate the rates and terms of service for our intrastate transportation service.

Sales of Natural Gas

We are engaged in natural gas marketing activities. The resale of natural gas in interstate commerce is subject to FERC jurisdiction.   However, under current federal rules, the price at which we sell natural gas is not regulated, insofar as the interstate market is concerned and, for the most part, is not subject to state regulation. The entities that engage in natural gas marketing are considered marketing affiliates of certain of our interstate natural gas pipelines. The FERC’s rules require pipelines and their marketing affiliates who sell natural gas in interstate commerce subject to the FERC’s jurisdiction to adhere to Standards of Conduct that, among other things, require that they function independently of each other. Pursuant to the Energy Policy Act of 2005, the FERC has also established rules prohibiting energy market manipulation. Those who violate the Standards of Conduct or these rules may be subject to civil penalties, suspension, or loss of authorization to perform such sales, disgorgement of unjust profits, or other appropriate non-monetary remedies imposed by the FERC.

The FERC is continually proposing and implementing new rules and regulations affecting segments of the natural gas industry. For example, the FERC recently established rules requiring certain non-interstate pipelines to post daily scheduled volume information and design capacity for certain points, and has also required the annual reporting of gas sales information, in order to increase transparency in natural gas markets. In November 2008, the FERC commenced an inquiry into whether to expand the contract reporting requirements of Section 311 service providers. We cannot predict the ultimate impact of these regulatory changes on our natural gas marketing activities; however, we believe that any new regulations will also be applied to other natural gas marketers with whom we compete.

Regulation of Our Intrastate NGL Pipelines and Storage Services

The intrastate liquids pipeline transportation services we provide are subject to various state laws and regulations that affect the rates we charge and terms and conditions of that service. Although state regulation typically is less onerous than FERC regulation, proposed and existing rates subject to state regulation and the provision of non-discriminatory service are subject to challenge by complaint.

Regulation of Our Petrochemical Services

Our Lou-Tex Propylene and Sabine Propylene Pipelines are interstate common carrier pipelines regulated by the Surface Transportation Board (“STB”), a part of the United States Department of Transportation, under the current version of the Interstate Commerce Act (“ICA”). The ICA and its implementing regulations give the STB authority to regulate the rates we charge for service on the propylene pipelines and generally require that our rates and practices be just and reasonable and not unduly discriminatory or preferential.

For additional information regarding the potential impact of federal, state or local regulatory measures on our business, please read Item 1A “Risk Factors.”

Environmental and Safety Matters

General

Our operations are subject to multiple environmental obligations and potential liabilities under a variety of federal, state and local laws and regulations. These include, without limitation: the Comprehensive Environmental Response, Compensation, and Liability Act; the Resource Conservation and Recovery Act; the Clean Air Act; the Federal Water Pollution Control Act or the Clean Water Act; the Oil Pollution Act; and analogous state and local laws and regulations. Such laws and regulations affect many aspects of our present and future operations, and generally require us to obtain and comply with a wide variety of environmental registrations, licenses, permits, inspections and other approvals, with respect to air emissions, water quality, wastewater discharges, and solid and hazardous waste management. Failure to comply with these requirements may expose us to fines, penalties and/or interruptions in our operations that could influence our results of operations. If an accidental leak, spill or release of hazardous substances occurs at a facility that we own, operate or otherwise use, or where we send materials for treatment or disposal, we could be held jointly and severally liable for all resulting liabilities, including investigation, remedial and clean-up costs. Likewise, we could be required to remove or remediate previously disposed wastes or property contamination, including groundwater contamination. Any or all of this could materially affect our financial position, results of operations and cash flows.

We believe our operations are in material compliance with applicable environmental and safety laws and regulations, and that compliance with existing environmental and safety laws and regulations are not expected to have a material adverse effect on our financial position, results of operations or cash flows. Environmental and safety laws and regulations are subject to change. The clear trend in environmental regulation is to place more restrictions and limitations on activities that may be perceived to affect the environment, and thus there can be no assurance as to the amount or timing of future expenditures for environmental regulation compliance or remediation, and actual future expenditures may be different from the amounts we currently anticipate. Revised or additional regulations that result in increased compliance costs or additional operating restrictions, particularly if those costs are not fully recoverable from our customers, could have a material adverse effect on our business, financial position, results of operations and cash flows. Below is a discussion of the material environmental laws and regulations that relate to our business.

Water

The Federal Water Pollution Control Act of 1972, renamed and amended as the Clean Water Act (“CWA”), and analogous state laws impose restrictions and strict controls regarding the discharge of pollutants into navigable waters of the United States, as well as state waters. Permits must be obtained to discharge pollutants into these waters. The CWA imposes substantial civil and criminal penalties for non-compliance. The EPA has promulgated regulations that require us to have permits in order to discharge storm water runoff. The EPA has entered into agreements with states in which we operate whereby the permits are administered by their respective states.

The primary federal law for oil spill liability is the Oil Pollution Act of 1990 (“OPA”), which addresses three principal areas of oil pollution -- prevention, containment and cleanup, and liability. OPA subjects owners of certain facilities to strict, joint and potentially unlimited liability for containment and removal costs, natural resource damages and certain other consequences of an oil spill, where such spill is into navigable waters, along shorelines or in the exclusive economic zone of the U.S. Any unpermitted release of petroleum or other pollutants from our operations could also result in fines or penalties. OPA applies to vessels, offshore platforms and onshore facilities, including terminals, pipelines and transfer facilities. In order to handle, store or transport oil, shore facilities are required to file oil spill response plans with the United States Coast Guard, the United States Department of Transportation Office of Pipeline Safety (“OPS”) or the EPA, as appropriate.

Some states maintain groundwater protection programs that require permits for discharges or operations that may impact groundwater conditions. Contamination resulting from spills or releases of petroleum products is an inherent risk within our industry. To the extent that groundwater contamination requiring remediation exists along our pipeline systems as a result of past operation, we believe any such contamination could be controlled or remedied without having a material adverse effect on our financial position, but such costs are site specific and we cannot ensure that the effect will not be material in the aggregate.

Air Emissions

Our operations are subject to the Federal Clean Air Act (the “Clean Air Act”) and comparable state laws and regulations. These laws and regulations regulate emissions of air pollutants from various industrial sources, including our facilities, and also impose various monitoring and reporting requirements. Such laws and regulations may require that we obtain pre-approval for the construction or modification of certain projects or facilities expected to produce air emissions or result in the increase of existing air emissions, obtain and strictly comply with air permits containing various emissions and operational limitations, or utilize specific emission control technologies to limit emissions.

Our permits and related compliance obligations under the Clean Air Act, as well as recent or soon to be adopted changes to state implementation plans for controlling air emissions in regional, non-attainment areas, may require our operations to incur capital expenditures to add to or modify existing air emission control equipment and strategies. In addition, some of our facilities are included within the categories of hazardous air pollutant sources, which are subject to increasing regulation under the Clean Air Act and many state laws. Our failure to comply with these requirements could subject us to monetary penalties, injunctions, conditions or restrictions on operations, and enforcement actions. We may be required to incur certain capital expenditures in the future for air pollution control equipment in connection with obtaining and maintaining operating permits and approvals for air emissions. We believe, however, that such requirements will not have a material adverse effect on our operations, and the requirements are not expected to be any more burdensome to us than to any other similarly situated companies.

Some 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 the warming of the Earth’s atmosphere. In response to such studies, the U.S. Congress is considering legislation to reduce emissions of greenhouse gases. In addition, at least 17 states have declined to wait on Congress to develop and implement climate control legislation and have already taken legal measures to reduce emissions of greenhouse gases. Also, as a result of the U.S. Supreme Court’s decision on April 2, 2007 in *Massachusetts*, *et al. v. EPA*, the EPA must consider whether it is required to regulate greenhouse gas emissions from mobile sources (e.g., cars and trucks) even if Congress does not adopt new legislation specifically addressing emissions of greenhouse gases. The Court’s holding in *Massachusetts* that greenhouse gases fall under the Federal Clean Air Act’s definition of “air pollutant” may also result in future regulation of greenhouse gas emissions from stationary sources under various Clean Air Act programs, including those that may be used in our operations. It is not possible at this time to predict how legislation that may be enacted to address greenhouse gas emissions would impact our business. However, future laws and regulations could result in increased compliance costs or additional operating restrictions, and could have a material adverse effect on our business, financial condition, demand for our operations, results of operations, and cash flows.

Solid Waste

In our normal operations, we generate hazardous and non-hazardous solid wastes, including hazardous substances that are subject to the requirements of the federal Resource Conservation and Recovery Act (“RCRA”) and comparable state laws, which impose detailed requirements for the handling, storage treatment and disposal of hazardous and solid waste. We also utilize waste minimization and recycling processes to reduce the volumes of our waste. Amendments to RCRA required the EPA to promulgate regulations banning the land disposal of all hazardous wastes unless the waste meets certain treatment standards or the land-disposal method meets certain waste containment criteria. In the past, although we utilized operating and disposal practices that were standard in the industry at the time, hydrocarbons and other materials may have been disposed of or released. In the future, we may be required to remove or remediate these materials.

Environmental Remediation

The Comprehensive Environmental Response, Compensation and Liability Act (“CERCLA”), also known as “Superfund” laws, imposes liability, without regard to fault or the legality of the original act, on certain classes of persons who contributed to the release of a “hazardous substance” into the environment. These persons include the owner or operator of a facility where a release occurred, transporters that select the site of disposal of hazardous substances and companies that disposed of or arranged for the disposal of any hazardous substances found at a facility. Under CERCLA, these persons may be subject to joint and several liabilities for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. CERCLA also authorizes the EPA and, in some instances, third parties to take actions in response to threats to the public health or the environment and to seek to recover the costs they incur from the responsible classes of persons. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances or other pollutants released into the environment. Despite the “petroleum exclusion” of CERCLA that currently encompasses natural gas, we may nonetheless handle “hazardous substances” subject to CERCLA in the course of our operations, and our pipeline systems may generate wastes that fall within CERCLA’s definition of a “hazardous substance.” In the event that a disposal facility previously used by us requires clean up in the future, we may be responsible under CERCLA for all or part of the costs required to clean up sites at which such wastes have been disposed.

Pipeline Safety Matters

We are subject to regulation by the United States Department of Transportation (“DOT”) under the Accountable Pipeline and Safety Partnership Act of 1996, sometimes referred to as the Hazardous Liquid Pipeline Safety Act (“HLPSA”), and comparable state statutes relating to the design, installation, testing, construction, operation, replacement and management of our pipeline facilities. The HLPSA covers petroleum and petroleum products and requires any entity that owns or operates pipeline facilities to comply with such regulations, to permit access to and copying of records and to file certain reports and provide information as required by the Secretary of Transportation. We believe we are in material compliance with these HLPSA regulations.

We are also subject to the DOT regulation requiring qualification of pipeline personnel. The regulation requires pipeline operators to develop and maintain a written qualification program for individuals performing covered tasks on pipeline facilities. The intent of this regulation is to ensure a qualified work force and to reduce the probability and consequence of incidents caused by human error. The regulation establishes qualification requirements for individuals performing covered tasks. We believe we are in material compliance with these DOT regulations.

In addition, we are subject to the DOT Integrity Management regulations, which specify how companies should assess, evaluate, validate and maintain the integrity of pipeline segments that, in the event of a release, could impact High Consequence Areas (“HCAs”). HCAs are defined to include populated areas, unusually sensitive environmental areas and commercially navigable waterways. The regulation requires the development and implementation of an Integrity Management Program that utilizes internal pipeline inspection, pressure testing, or other equally effective means to assess the integrity of HCA pipeline segments. The regulation also requires periodic review of HCA pipeline segments to ensure that adequate preventative and mitigative measures exist and that companies take prompt action to address integrity issues raised by the assessment and analysis. We have identified our HCA pipeline segments and developed an appropriate Integrity Management Program.

Risk Management Plans

We are subject to the EPA’s Risk Management Plan (“RMP”) regulations at certain facilities. These regulations are intended to work with the Occupational Safety and Health Act (“OSHA”) Process Safety Management regulations (see “Safety Matters” below) to minimize the offsite consequences of catastrophic releases. The regulations require us to develop and implement a risk management program that includes a five-year accident history, an offsite consequence analysis process, a prevention program and an emergency response program. Generally, we believe we are operating in compliance with our risk management program.

Safety Matters

Certain of our facilities are also subject to the requirements of the federal OSHA and comparable state statutes. We believe we are in material compliance with OSHA and state requirements, including general industry standards, record keeping requirements and monitoring of occupational exposures.

We are subject to OSHA Process Safety Management ("PSM") regulations, which are designed to prevent or minimize the consequences of catastrophic releases of toxic, reactive, flammable or explosive chemicals. These regulations apply to any process involving a chemical at or above the specified thresholds or any process involving certain flammable liquid or gas. We believe we are in material compliance with the OSHA PSM regulations.

The OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act and comparable state statutes require us to organize and disclose information about the hazardous materials used in our operations. Certain parts of this information must be reported to federal, state and local governmental authorities and local citizens upon request.

Employees

We have no employees. All of our management, administrative and operating functions are performed either by employees of EPCO pursuant to our administrative services agreement ("ASA") or by other service providers. As of December 31, 2008, there were approximately 1,800 EPCO personnel that spend all or a portion of their time engaged in our business. Approximately 400 of these individuals devote all of their time performing management and operating duties for us. We reimburse EPCO for 100% of the costs it incurs to employ these individuals. The remaining approximately 1,400 personnel are part of EPCO's shared service organization and spend all or a portion of their time engaged in our business. The cost for their services is reimbursed to EPCO under the ASA and is generally based on the percentage of time such employees perform services on our behalf during the year. For additional information regarding the ASA and our relationship with EPCO, see "Relationship with EPCO" under Item 13 of this annual report.

Available Information

We electronically file certain documents with the U.S. Securities and Exchange Commission ("SEC"). We file annual reports on Form 10-K; quarterly reports on Form 10-Q; and current reports on Form 8-K (as appropriate); along with any related amendments and supplements thereto. From time-to-time, we may also file registration statements and related documents in connection with equity or debt offerings. You may read and copy any materials we file with the SEC at the SEC's Public Reference Room at 100 F Street, NE, Washington, DC 20549. You may obtain information regarding the Public Reference Room by calling the SEC at 1-800-SEC-0330. In addition, the SEC maintains an Internet website at www.sec.gov that contains reports and other information regarding registrants that file electronically with the SEC.

Item 1A. Risk Factors.

An investment in our common units involves certain risks. If any of these risks were to occur, our business, results of operations, cash flows and financial condition could be materially adversely affected. In that case, the trading price of our common units could decline, and you could lose part or all of your investment.

The following section lists some, but not all, of the key risk factors that may have a direct impact on our business, results of operations, cash flows and financial condition.

Risks Inherent in Our Business

Changes in demand for and production of hydrocarbon products may materially adversely affect our results of operations, cash flows and financial condition.

We operate predominantly in the midstream energy sector that includes transporting and storing natural gas, NGLs and propylene. As such, our results of operations, cash flows and financial condition may be materially adversely affected by changes in the prices of these hydrocarbon products and by changes in the relative price levels among these hydrocarbon products. Changes in prices and changes in the relative price levels may impact demand for hydrocarbon products, which in turn may impact production and volumes transported by us and related transportation and storage handling fees. We may also incur price risk to the extent counterparties do not perform in connection with our marketing of natural gas.

In the past, the prices of natural gas have been extremely volatile, and we expect this volatility to continue. The NYMEX daily settlement price for natural gas for the prompt month contract in 2006, ranged from a high of $10.63 per MMBtu to a low of $4.20 per MMBtu. In 2007, the NYMEX daily settlement price for natural gas ranged from a high of $8.64 per MMBtu to a low of $5.38 per MMBtu. In 2008, the NYMEX daily settlement price for natural gas ranged from a high of $13.58 per MMBtu to a low of $5.29 per MMBtu.

Generally, the prices of natural gas, NGLs and other hydrocarbon products are subject to fluctuations in response to changes in supply, demand, market uncertainty and a variety of additional factors that are impossible to control. These factors include:

§ the level of domestic production and consumer product demand;

§ the availability of imported natural gas;

§ actions taken by foreign natural gas producing nations;

§ the availability of transportation systems with adequate capacity;

§ the availability of competitive fuels;

§ fluctuating and seasonal demand for natural gas and NGLs;

§ the impact of conservation efforts;

§ the extent of governmental regulation and taxation of production; and

§ the overall economic environment.

We are indirectly exposed to natural gas and NGL commodity price risk. An increase in natural gas prices or a decrease in NGL prices could result in a decrease in the volume of NGLs fractionated by our Shoup and Armstrong fractionators, which would result in a decrease in gross operating margin for the South Texas NGL System.

A decrease in demand for natural gas, NGL products or petrochemical products by the petrochemical, refining or heating industries could materially adversely affect our results of operations, cash flows and financial position.

A general downturn in economic conditions, reduced demand by consumers for the end products made with products we process or transport, increased competition from petroleum-based products due to pricing differences, adverse weather conditions, increased government regulations affecting prices and production levels of natural gas, or other reasons, could result in a decrease in demand for natural gas, NGL products or petrochemical products by the petrochemical, refining or heating industries. Such a decrease could materially adversely affect our results of operations, cash flows and financial position. For example:

- § *Ethane*. Ethane is primarily used in the petrochemical industry as feedstock for ethylene, one of the basic building blocks for a wide range of plastics and other chemical products. If natural gas prices increase significantly in relation to NGL product prices, or if the demand for ethylene falls (and, therefore, the demand for ethane by NGL producers falls), it may be more profitable for natural gas producers to leave the ethane in the natural gas stream to be burned as fuel than to extract the ethane from the mixed NGL stream for sale as an ethylene feedstock.

- § *Propylene*. Propylene is sold to petrochemical companies for a variety of uses, principally for the production of polypropylene. Propylene is subject to rapid and material price fluctuations. Any downturn in the domestic or international economy could cause reduced demand for, and an oversupply of propylene, which could cause a reduction in the volumes of propylene that we transport.

Any decrease in supplies of natural gas could adversely affect our business and operating results. Our success depends on our ability to obtain access to new sources of natural gas from both domestic production and LNG terminals, which sources are dependent on factors beyond our control.

We cannot give any assurance regarding the natural gas production industry's ability to find new sources of domestic supply. Production from existing wells and gas supply basins connected to our pipelines will naturally decline over time, which means our cash flows associated with the gathering or transportation of gas from these wells and basins will also decline over time. The amount of natural gas reserves underlying these wells may also be less than we anticipate, and the rate at which production from these reserves declines may be greater than we anticipate. Accordingly, to maintain or increase throughput levels on our pipelines, we must continually obtain access to new supplies of natural gas. The primary factors affecting our ability to obtain new sources of natural gas to our pipelines include:

- § the level of successful drilling activity near our pipelines;

- § our ability to compete for these supplies;

- § our ability to connect our pipelines to the suppliers;

- § the successful completion of new liquefied natural gas ("LNG") facilities near our pipelines; and

- § our gas quality requirements.

The level of drilling activity is dependent on economic and business factors beyond our control. The primary factor that impacts drilling decisions is the price of oil and natural gas. These commodity prices reached record levels during 2008, but current prices have declined in recent months. A sustained decline in natural gas prices could result in a decrease in exploration and development activities in the fields served by our pipelines, which would lead to reduced throughput levels on our pipelines. Other factors that impact production decisions include producers' capital budget limitations, the ability of producers to obtain necessary drilling and other governmental permits, the availability and cost of drilling rigs and other drilling equipment, and regulatory changes. Because of these factors, even if new natural gas reserves were discovered in areas served by our pipelines, producers may choose not to develop those reserves or may connect them to different pipelines.

Imported LNG is expected to be a significant component of future natural gas supply to the United States. Much of this increase in LNG supplies is expected to be imported through new LNG facilities to be developed over the next decade. Twelve LNG projects have been approved by the FERC to be constructed in the Gulf Coast region and an additional two LNG projects have been proposed for the region. We cannot predict which, if any, of these projects will be constructed. If a significant number of these new projects fail to be developed with their announced capacity, or there are significant delays in such development, or if they are built in locations where they are not connected to our systems, or they do not influence sources of supply on our systems, we may not realize expected increases in future natural gas supply available for transportation through our systems.

If we are not able to obtain new supplies of natural gas to replace the natural decline in volumes from existing supply basins, or if the expected increase in natural gas supply through imported LNG is not realized, throughput on our pipelines would decline, which could have a material adverse effect on our financial condition, results of operations and ability to make distributions to our unitholders.

In accordance with industry practice, we do not obtain independent evaluations of natural gas and NGL reserves dedicated to our pipeline systems, including our South Texas NGL Pipeline & Storage System. Accordingly, volumes of natural gas gathered on our pipeline systems in the future could be less than we anticipate, which could adversely affect our cash flow and our ability to make cash distributions to unitholders.

In accordance with industry practice, we do not obtain independent evaluations of natural gas reserves connected to our pipeline systems due to the unwillingness of producers to provide reserve information as well as the cost of such evaluations. Accordingly, we do not have estimates of total reserves dedicated to our systems (or to processing and fractionation facilities such as those serving EPO in South Texas) or the anticipated lives of such reserves. If the total reserves or estimated lives of the reserves connected to our pipeline systems, particularly in South Texas, is less than we anticipate and we are unable to secure additional sources of natural gas or NGLs, then the volumes of NGLs transported gathered on our South Texas NGL Pipeline System or natural gas gathered on our Acadian Gas System and other pipeline systems in the future could be less than we anticipate. A decline in the volumes of natural gas or NGLs gathered on our pipeline systems could have an adverse effect on our business, results of operations, financial condition and our ability to make cash distributions to our unitholders.

We face competition from third parties in our midstream energy businesses.

Even if reserves exist in the areas accessed by our facilities and are ultimately produced, we may not be chosen by the producers in these areas to gather, transport, market, store or otherwise handle the hydrocarbons that are produced. We compete with others, including producers of oil and natural gas, for any such production on the basis of many factors, including but not limited to:

§ geographic proximity to the production;

§ costs of connection;

§ available capacity;

§ rates; and

§ access to markets.

Our debt level may limit our flexibility to obtain additional financing and pursue other business opportunities.

As of December 31, 2008, we had $202.0 million of indebtedness outstanding under our credit agreement, with the ability to borrow up to an additional $98.0 million, subject to certain conditions and limitations, under the credit agreement. We also had an additional $282.3 million of indebtedness outstanding under our senior unsecured term loan related to our purchase of equity interests in the DEP II Midstream Businesses. Our significant level of indebtedness could have important consequences to us, including:

§ our ability to obtain additional financing, if necessary, for working capital, capital expenditures, acquisitions or other purposes may be impaired or such financing may not be available on favorable terms;

- § covenants contained in our existing and future credit and debt arrangements require us to meet certain financial tests that may affect our flexibility in planning for and reacting to changes in our business, including possible acquisition opportunities;

- § we may need a substantial portion of our cash flow to make principal and interest payments on our indebtedness, reducing the funds that would otherwise be available for operation, future business opportunities and distributions to unitholders; and

- § our debt level may make us more vulnerable than our competitors with less debt to competitive pressures or a downturn in our business or the economy generally.

Our ability to service our indebtedness will depend upon, among other things, our future financial and operating performance, which may be affected by prevailing economic conditions and financial, business, regulatory and other factors, some of which are beyond our control. If our operating results are not sufficient to service our current or future indebtedness, we may be forced to take actions such as reducing distributions, reducing or delaying business activities, acquisition, investments or capital expenditures, selling assets, restructuring or refinancing our indebtedness, or seeking additional equity capital or bankruptcy protection. We may not be able to affect any of these remedies on satisfactory terms or at all.

Increases in interest rates could materially adversely affect our business, results of operations, cash flows and financial condition.

We have exposure to increases in interest rates. As of December 31, 2008, we effectively had $309.3 million of consolidated variable-rate debt. As a result, significant increases in interest rates could adversely affect our results of operations, cash flows and financial condition.

An increase in interest rates may also cause a corresponding decline in demand for equity investments, in general, and in particular for yield-based equity investments such as our common units. Any such reduction in demand for our common units resulting from other more attractive investment opportunities may cause the trading price of our common units to decline.

We may not be able to fully execute our growth strategy if we encounter illiquid capital markets or increased competition for investment opportunities.

Our strategy contemplates growth through the development and acquisition of a wide range of midstream and other energy infrastructure assets while maintaining a strong balance sheet. This strategy includes constructing and acquiring additional assets and businesses to enhance our ability to compete effectively and diversifying our asset portfolio, thereby providing more stable cash flow. We regularly consider and enter into discussions regarding, and are currently contemplating and/or pursuing, potential joint ventures, stand alone projects or other transactions that we believe may present opportunities to realize synergies, expand our role in the energy infrastructure business and increase our market position.

We will require substantial new capital to finance the future development and acquisition of assets and businesses. Any limitations on our access to capital may impair our ability to execute this strategy. If the cost of such capital becomes too expensive, our ability to develop or acquire accretive assets will be limited. We may not be able to raise the necessary funds on satisfactory terms, if at all. The primary factors that influence our initial cost of equity include market conditions, fees we pay to underwriters and other offering costs, which include amounts we pay for legal and accounting services. The primary factors influencing our cost of borrowing include interest rates, credit spreads, covenants, underwriting or loan origination fees and similar charges we pay to lenders.

Recent conditions in the financial markets have had an adverse impact on our ability to access equity and credit markets. As a result, the availability of credit has become more expensive and difficult to obtain, and the cost of equity capital has also become more expensive. Some lenders are imposing more stringent restrictions on the terms of credit and there may be a general reduction in the amount of credit available in the markets in which we conduct business. The negative impact on the tightening of the credit markets may have a material adverse effect on us resulting from, but not limited to, an inability to expand facilities or finance the acquisition of assets on favorable terms, if at all, increased financing costs or financing with increasingly restrictive covenants. In addition, the distribution yields of new equity issued may be higher than our historical levels, making additional equity issuances more expensive.

We also compete for the types of assets and businesses we would likely be interested in purchasing or acquiring. Increased competition for a limited pool of assets could result in our losing to other bidders more often or acquiring assets at less attractive prices. Either occurrence would limit our ability to fully execute our growth strategy. Our inability to execute our growth strategy may materially adversely affect our ability to maintain or pay higher distributions in the future.

Our revolving credit facility contains operating and financial restrictions, including covenants and restrictions that may be affected by events beyond our control, that may limit our business and financing activities.

The operating and financial restrictions and covenants in our credit agreement and any future financing agreements could restrict our ability to finance future operations or capital needs or to expand or pursue our business activities. For example, our credit agreement may restrict or limit our ability to:

§ make distributions if any default or event of default occurs;

§ incur additional indebtedness or guarantee other indebtedness;

§ grant liens or make certain negative pledges;

§ make certain loans or investments;

§ make any material change to the nature of our business, including consolidations, liquidations and dissolutions; or

§ enter into a merger, consolidation, sale and leaseback transaction or sale of assets.

Our ability to comply with the covenants and restrictions contained in our credit agreement may be affected by events beyond our control, including prevailing economic, financial and industry conditions. If market or other economic conditions deteriorate, our ability to comply with these covenants may be impaired. If we violate any of the restrictions, covenants, ratios or tests in our credit agreement, a significant portion of our indebtedness may become immediately due and payable, and our lenders' commitment to make further loans to us may terminate. We might not have, or be able to obtain, sufficient funds to make these accelerated payments.

Restrictions in our revolving credit facility could limit our ability to make distributions upon the occurrence of certain events.

Our payment of principal and interest on our debt will reduce cash available for distributions on our common units. Furthermore, our credit agreement could limit our ability to make distributions upon the occurrence of the following events, among others:

§ failure to pay any principal, interest, fees, expenses or other amounts when due;

§ failure of any representation or warranty to be true and correct in any material respect;

- § failure to perform or otherwise comply with the covenants in the credit agreement;
- § failure to pay any other material debt;
- § a bankruptcy or insolvency event involving us, our general partner or any of our subsidiaries;
- § the entry of, and failure to pay, one or more adverse judgments in excess of a specified amount against which enforcement proceedings are brought or that are not stayed pending appeal;
- § a change in control of us;
- § a judgment default or a default under any material agreement if such default could have a material adverse effect on us; and
- § the occurrence of certain events with respect to employee benefit plans subject to ERISA.

Any subsequent refinancing of our current debt or any new debt could have similar or more restrictive provisions. For more information regarding our credit agreement, see Item 7.

Our pipeline integrity program may impose significant costs and liabilities on us.

The U.S. Department of Transportation issued final rules (effective March 2001 with respect to hazardous liquid pipelines and February 2004 with respect to natural gas pipelines) requiring pipeline operators to develop integrity management programs to comprehensively evaluate their pipelines, and take measures to protect pipeline segments located in what the rules refer to as "high consequence areas." The final rule resulted from the enactment of the Pipeline Safety Improvement Act of 2002. At this time, we cannot predict the ultimate costs of compliance with this rule because those costs will depend on the number and extent of any repairs found to be necessary as a result of the pipeline integrity testing that is required by the rule. We will continue our pipeline integrity testing programs to assess and maintain the integrity of our pipelines. The results of these tests could cause us to incur significant and unanticipated capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operation of our pipelines.

Our growth strategy may adversely affect our results of operations if we do not successfully integrate the businesses that we acquire or if we substantially increase our indebtedness and contingent liabilities to make acquisitions.

Our growth strategy includes making accretive acquisitions. As a result, from time to time, we will evaluate and acquire assets and businesses that we believe complement our existing operations. We may be unable to integrate successfully businesses we acquire in the future. We may incur substantial expenses or encounter delays or other problems in connection with our growth strategy that could negatively impact our results of operations, cash flows and financial condition. Moreover, acquisitions and business expansions involve numerous risks, including but not limited to:

- § difficulties in the assimilation of the operations, technologies, services and products of the acquired companies or business segments;
- § establishing the internal controls and procedures that we are required to maintain under the Sarbanes-Oxley Act of 2002;
- § managing relationships with new joint venture partners with whom we have not previously partnered;
- § inefficiencies and complexities that can arise because of unfamiliarity with new assets and the businesses associated with them, including with their markets; and

- § diversion of the attention of management and other personnel from day-to-day business to the development or acquisition of new businesses and other business opportunities.

If consummated, any acquisition or investment would also likely result in the incurrence of indebtedness and contingent liabilities and an increase in interest expense and depreciation, depletion and amortization expenses. As a result, our capitalization and results of operations may change significantly following an acquisition. A substantial increase in our indebtedness and contingent liabilities could have a material adverse effect on our results of operations, cash flows and financial condition. In addition, any anticipated benefits of material acquisition, such as expected cost savings, may not be fully realized, if at all.

Because our general partner does not own incentive distribution rights in our distributions, we may elect to acquire or build energy infrastructure assets that have a lower expected return on investment than a similarly situated publicly traded energy partnership whose partner owns incentive distribution rights.

Duncan Energy Partners was formed in part to support the growth objectives of EPO. EPO, the owner of our general partner, elected to forgo incentive distribution rights with respect to our distributions for the purpose of reducing our expected long-term cost of equity capital. This should allow us to acquire or build energy infrastructure assets with lower expected returns on investment that should still be accretive on a per unit basis. Such expected returns on investment may not be considered economically viable by other similarly situated publicly traded partnerships whose general partner owns incentive distribution rights, including Enterprise Products Partners. In addition, we may elect to participate in capital projects with Enterprise Products Partners and/or TEPPCO Partners, L.P. ("TEPPCO"), whereby our expected return on investment may be lower than that of Enterprise Products Partners and/or TEPPCO, yet is still ultimately expected to be accretive on a per unit basis for our common units. Should the returns and cash flow from operations from such acquisitions or capital projects not materialize as expected, we may not be able to support our cash distribution rate at current levels or increase our cash distribution rate to partners in the future.

We may not be able to make acquisitions or to make acquisitions on economically acceptable terms, which may limit our ability to grow.

We are limited in our ability to make acquisitions by our business opportunity agreements with EPO and Enterprise GP Holdings. These agreements entitle them to take business opportunities for the benefit of themselves before allowing us to take them. In addition, our ability to grow depends, in part, on our ability to make acquisitions that result in an increase in the cash generated from operations per unit. If we are unable to make these accretive acquisitions either because we are (1) unable to identify attractive acquisition candidates or negotiate acceptable purchase contracts with them, (2) unable to obtain financing for these acquisitions on economically acceptable terms, or (3) outbid by competitors, then our future growth and ability to maintain and increase over time distributions will be limited.

Acquisitions that appear to be accretive may nevertheless reduce our cash from operations on a per unit basis.

Even if we make acquisitions that we believe will be accretive, these acquisitions may nevertheless reduce our cash from operations on a per unit basis. Any acquisition involves potential risks, including, among other things:

- § mistaken assumptions about volumes, revenues and costs, including synergies;
- § an inability to integrate successfully the businesses we acquire;
- § a decrease in our liquidity as a result of our using a significant portion of our available cash or borrowing capacity to finance the acquisition;

§ a significant increase in our interest expense or financial leverage if we incur additional debt to finance the acquisition;

§ the assumption of unknown liabilities for which we are not indemnified or for which our indemnity is inadequate;

§ an inability to hire, train or retain qualified personnel to manage and operate our growing business and assets;

§ limitations on rights to indemnity from the seller;

§ mistaken assumptions about the overall costs of equity or debt;

§ the diversion of management’s and employees’ attention from other business concerns;

§ unforeseen difficulties operating in new product areas or new geographic areas; and

§ customer or key employee losses at the acquired businesses.

If we consummate any future acquisitions, our capitalization and results of operations may change significantly, and our unitholders will not have the opportunity to evaluate the economic, financial and other relevant information that we will consider in determining the application of these funds and other resources.

We depend in large part on EPO and the continued success of its business as we operate our assets as part of their value chain, and adverse changes in its related businesses may reduce our revenue, earnings or cash available for distribution.

We have entered into a number of material contracts with EPO and its subsidiaries relating to transportation and storage services and leases. Our cash flows and financial condition depend in large part on the continued success of EPO as we operate our assets as part of its value chain. For example, our South Texas NGL Pipeline System revenues depend largely on the volumes processed at the South Texas facilities owned by EPO. EPO has no obligation to produce any volumes at these facilities. If anticipated volumes are not processed by EPO at these facilities, our estimated revenues on this system will be reduced.

Any adverse changes in the business of EPO, due to market conditions, sales of assets or otherwise, or the failure of EPO to renew any of its material agreements with us, could reduce our revenue, earnings or cash available for distribution. See Item 13 for additional information regarding certain agreements with EPO.

The interruption of distributions to us from our subsidiaries may affect our ability to satisfy our obligations and to make distributions to our partners.

We are a holding company with no business operations, and our operating subsidiaries conduct all of our operations and own all of our operating assets. Our only significant assets are the ownership interests we own in our subsidiaries. As a result, we depend upon the earnings and cash flow of our subsidiaries and joint ventures and the distribution of that cash to us in order to meet our obligations and to allow us to make distributions to our partners. The ability of our subsidiaries to make distributions to us may be restricted by, among other things, the provisions of existing and future indebtedness, applicable state partnership and limited liability company laws and other laws and regulations, including FERC policies.

As of December 8, 2008, we also own a membership interest in Enterprise Texas, which interest has a stated fixed return. Although we have effective priority rights to specified quarterly distribution amounts ahead of any distributions on EPO’s minority equity interests in Enterprise Texas, the inability of

Enterprise Texas Pipeline to make distributions of the fixed returns in full each quarter would have a material adverse impact on our ability to make distributions to our partners and could affect our ability to satisfy other debt obligations.

The credit and risk profile of our general partner and its owners could adversely affect our credit ratings and risk profile, which could increase our borrowing costs or hinder our ability to raise capital.

The credit and business risk profiles of a general partner or owners of a general partner may be factors in credit evaluations of a limited partnership by the nationally recognized debt rating agencies. This is because the general partner controls the business activities of the partnership, including its cash distribution policy and acquisition strategy and business risk profile. Another factor that may be considered is the financial condition of our general partner and its owners, including the degree of their financial leverage and their dependence on cash flow from the partnership to service their indebtedness.

If we were to seek a credit rating in the future, our credit rating may be adversely affected by the leverage of the owners of our general partner, as credit rating agencies may consider these entities' leverage because of their ownership interest in and control of us, the strong operational links between them and their affiliates and us, and our reliance on EPO for a substantial percentage of our revenue. Any such adverse effect on our credit rating would increase our cost of borrowing or hinder our ability to raise money in the capital markets, which would impair our ability to grow our business and make distributions to unitholders.

Affiliates of EPCO and Enterprise Products Partners, the indirect owner of our general partner, have significant indebtedness outstanding and are dependent principally on the cash distributions from their limited partner interests in Enterprise Products Partners, Enterprise GP Holdings and TEPPCO to service such indebtedness. Any distributions by Enterprise Products Partners, Enterprise GP Holdings and TEPPCO to such entities will be made only after satisfying their then-current obligations to their creditors. Although we have taken certain steps in our organizational structure, financial reporting and contractual relationships to reflect the separateness of us and our general partner from the entities that control our general partner, and other entities controlled by EPCO, our credit ratings and business risk profile could be adversely affected if the ratings and risk profiles of EPCO or the entities that control our general partner were viewed as substantially lower or more risky than ours.

A natural disaster, catastrophe or other event could result in severe personal injury, property damage and environmental damage, which could curtail our operations and otherwise materially adversely affect our cash flow and, accordingly, affect the market price of our common units.

Some of our operations involve risks of personal injury, property damage and environmental damage, which could curtail our operations and otherwise materially adversely affect our cash flow. For example, natural gas facilities operate at high pressures, sometimes in excess of 1,100 pounds per square inch. Pipelines may suffer inadvertent damage from construction, farm and utility equipment. Virtually all of our operations are exposed to potential natural disasters, including hurricanes, tornadoes, storms and floods. The location of our assets and our customers' assets in the Gulf Coast region makes them particularly vulnerable to hurricane risk.

If one or more facilities that we own or that deliver natural gas or other products to us are damaged by severe weather or any other disaster, accident, catastrophe or event, our operations could be significantly interrupted. Similar interruptions could result from damage to production or other facilities that supply our facilities or other stoppages arising from factors beyond our control. These interruptions might involve significant damage to people, property or the environment, and repairs might take from a week or less for a minor incident to six months or more for a major interruption. Any event that interrupts the revenues generated by our operations, or which causes us to make significant expenditures not covered by insurance, could reduce our cash available for paying distributions and, accordingly, adversely affect the market price of our common units.

EPCO maintains insurance coverage on behalf of us, although insurance will not cover many types of interruptions that might occur and will not cover amounts up to applicable deductibles. As a result of market conditions, premiums and deductibles for certain insurance policies can increase substantially, and in some instances, certain insurance may become unavailable or available only for reduced amounts of coverage. For example, changes in the insurance markets subsequent to the hurricanes in 2005 and 2008 have made it more difficult for us to obtain certain types of coverage. As a result, EPCO may not be able to renew existing insurance policies on behalf of us or procure other desirable insurance on commercially reasonable terms, if at all. If we were to incur a significant liability for which we were not fully insured, it could have a material adverse effect on our financial position and results of operations. In addition, the proceeds of any such insurance may not be paid in a timely manner and may be insufficient if such an event were to occur.

Our construction of new assets is subject to regulatory, environmental, political, legal and economic risks, which may result in delays, increased costs or decreased cash flows.

We cannot ensure that our construction projects will not be delayed due to government permits, weather conditions or other factors beyond our control. In addition, one of the ways we intend to grow our business is through the construction of new midstream energy assets. The construction of new assets involves numerous operational, regulatory, environmental, political and legal risks beyond our control and may require the expenditure of significant amounts of capital. These potential risks include, among other things, the following:

§ we may be unable to complete construction projects on schedule or at the budgeted cost due to the unavailability of required construction personnel or materials, accidents, weather conditions or an inability to obtain necessary permits;

§ we will not receive any material increases in revenues until the project is completed, even though we may have expended considerable funds during the construction phase, which may be prolonged;

§ we may construct facilities to capture anticipated future growth in production or demand in a region in which such growth does not materialize;

§ since we are not engaged in the exploration for and development of natural gas reserves, we may not have access to third-party estimates of reserves in an area prior to our constructing facilities in the area. As a result, we may construct facilities in an area where the reserves are materially lower than we anticipate;

§ where we do rely on third-party estimates of reserves in making a decision to construct facilities, these estimates may prove to be inaccurate because there are numerous uncertainties inherent in estimating reserves; and

§ we may be unable to obtain rights-of-way to construct additional pipelines or the cost to do so may be uneconomical.

The occurrence of any of these risks could adversely affect our ability to achieve growth in the level of our cash flows or realize benefits from expansion opportunities or construction projects.

Federal, state or local regulatory measures could materially affect our business, results of operations, cash flows and financial condition.

The intrastate natural gas pipeline transportation services we provide are subject to various Louisiana state laws and regulations that apply to the rates we charge and the terms and conditions of the services we offer. Although state regulation typically is less onerous than FERC regulation, the rates we charge and the provision of our services may be subject to challenge. In addition, the transportation and storage services furnished by our intrastate natural gas facilities on behalf of interstate natural gas pipelines or certain local distribution companies are regulated by the FERC pursuant to Section 311 of the NGA. Pursuant to the NGA, we are required to offer those services on an open and nondiscriminatory basis at a fair and equitable rate. Such FERC-regulated NGA Section 311 rates also may be subject to challenge and successful challenges may adversely affect our revenues.

Although our natural gas gathering systems are generally exempt from FERC regulation under the Natural Gas Act of 1938, FERC regulation still significantly affects our natural gas gathering business. In recent years, the FERC has pursued pro-competition policies in its regulation of interstate natural gas pipelines. If the FERC does not continue this approach, it could have an adverse effect on the rates we are able to charge in the future. In addition, the distinction between FERC-regulated transmission service and federally unregulated gathering services is the subject of regular litigation, so, in such a circumstance, the classification and regulation of some of our gathering facilities may be subject to change based on future determinations by the FERC and the courts. Additional rules and legislation pertaining to these matters are considered and adopted from time to time. We cannot predict what effect, if any, such regulatory changes and legislation might have on our operations, but we could be required to incur additional capital expenditures.

The tariff rates and terms of service of the intrastate liquids pipeline transportation services we provide are subject to various state laws and regulations. Although state regulation typically is less onerous than FERC regulation, our intrastate rates and terms of service are subject to challenge by complaint.

The STB regulates transportation on interstate propylene pipelines. The current version of the ICA and its implementing regulations give the STB authority to regulate the rates we charge for service on the propylene pipelines and generally requires that our rates and practices be just and reasonable and nondiscriminatory. The rates we charge for movements on our propylene pipelines may be subject to challenge and any successful challenge to those rates could adversely affect our revenues. Our interstate propylene pipelines formerly were regulated by the FERC, and we cannot guarantee that the FERC will not reassert jurisdiction over those facilities in the future.

For a general overview of federal, state and local regulation applicable to our assets, see Item 1.

Environmental costs and liabilities and changing environmental regulation, including climate change regulation, could materially affect our results of operations, cash flows and financial condition.

Our operations are subject to extensive federal, state and local regulatory requirements relating to environmental affairs, health and safety, waste management and chemical and petroleum products. Further, we cannot ensure that existing environmental regulations will not be revised or that new regulations, such as regulations designed to reduce the emissions of greenhouse gases, will not be adopted or become applicable to us. Governmental authorities have the power to enforce compliance with applicable regulations and permits and to subject violators to civil and criminal penalties, including substantial fines, injunctions or both. Certain environmental laws, including CERCLA and analogous state laws and regulations, impose strict, joint and several liability for costs required to cleanup and restore sites where hazardous substances or hydrocarbons have been disposed or otherwise released. Moreover, third parties, including neighboring landowners, may also have the right to pursue legal actions to enforce compliance or to recover for personal injury and property damage allegedly caused by the release of hazardous substances, hydrocarbons or other waste products into the environment.

We will make expenditures in connection with environmental matters as part of normal capital expenditure programs. However, future environmental law developments, such as stricter laws, regulations, permits or enforcement policies, could significantly increase some costs of our operations, including the handling, manufacture, use, emission or disposal of substances and wastes.

Climate change regulation is one area of potential future environmental law development. Studies have suggested that emissions of certain gases, commonly referred to as “greenhouse gases,” may be contributing to warming of the Earth’s atmosphere. Methane, a primary component of natural gas, and carbon dioxide, a byproduct of the burning of natural gas, are examples of greenhouse gases. The U.S. Congress is considering legislation to reduce emissions of greenhouse gases. In addition, at least nine states in the Northeast and five states in the West have developed initiatives to regulate emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. The EPA is separately considering whether it will regulate greenhouse gases as "air pollutants" under the existing federal Clean Air Act.

Passage of climate control legislation or other regulatory initiatives by Congress or various states of the U.S. or the adoption of regulations by the EPA or analogous state agencies that regulate or restrict emissions of greenhouse gases, including methane or carbon dioxide in areas in which we conduct business, could result in changes to the consumption and demand for natural gas and could have adverse effects on our business, financial position, results of operations and prospects. These changes could increase the costs of our operations, including costs to operate and maintain our facilities, install new emission controls on our facilities, acquire allowances to authorize our greenhouse gas emissions, pay any taxes related to our greenhouse gas emissions and administer and manage a greenhouse gas emissions program. While we may be able to include some or all of such increased costs in the rates charged by our pipelines or other facilities, such recovery of costs is uncertain and may depend on events beyond our control, including the outcome of future rate proceedings before the FERC and the provisions of any final legislation.

We are subject to strict regulations at many of our facilities regarding employee safety, and failure to comply with these regulations could adversely affect our ability to make distributions to our unitholders.

The workplaces associated with our pipelines are subject to the requirements of OSHA and comparable state statutes that regulate the protection of the health and safety of workers. In addition, the OSHA hazard communication standard requires that we maintain information about hazardous materials used or produced in our operations and that we provide this information to employees, state and local governmental authorities and local residents. The failure to comply with OSHA requirements or general industry standards, keep adequate records or monitor occupational exposure to regulated substances could have a material adverse effect on our business, financial condition, results of operations and ability to make distributions to our unitholders.

We depend on EPO and certain other key customers for a significant portion of our revenues. The loss of any of these key customers could result in a decline in our revenues and cash available to make distributions to our unitholders.

We rely on a limited number of customers for a significant portion of revenues. For the year ended December 31, 2008 and 2007, EPO and its affiliates accounted for approximately 46% and 38% of our total consolidated revenues, respectively. In addition, several of our assets also rely on only one or two customers for the asset's cash flow. For example, the only shipper on a segment of our South Texas NGL Pipeline System is EPO; there are only two customers on our Lou-Tex Propylene Pipeline; there is only one customer on our Sabine Propylene Pipeline; and there is only one shipper on the pipeline held by Evangeline. In order for new customers to use these pipelines, we or the new shippers would be required to construct interim pipeline connections.

We may be unable to negotiate extensions or replacements of these contracts and those with other key customers on favorable terms. The loss of all or even a portion of the contracted volumes of these customers, as a result of competition, creditworthiness or otherwise, could have a material adverse effect on our financial condition, results of operations and ability to make distributions to our unitholders, unless we are able to contract for comparable volumes from other customers at favorable rates.

We are exposed to the credit risks of our key customers, and any material nonpayment or nonperformance by our key customers could reduce our ability to make distributions to our unitholders.

We are subject to risks of loss resulting from nonpayment or nonperformance by our customers. Any material nonpayment or nonperformance by our key customers could reduce our ability to make distributions to our unitholders. Furthermore, some of our customers may be highly leveraged and subject to their own operating and regulatory risks. We generally do not require collateral for our accounts receivable. If we fail to adequately assess the creditworthiness of existing or future customers, unanticipated deterioration in their creditworthiness and any resulting increase in nonpayment or nonperformance by them could have a material adverse effect on our business, results of operations, financial condition and ability to make cash distributions to our unitholders.

We depend on the leadership and involvement of Dan L. Duncan and other key personnel for the success of our and our subsidiaries' businesses.

We depend on the leadership, involvement and services of Dan L. Duncan, the founder of EPCO and the Chairman of our general partner. Mr. Duncan has been integral to the success of EPO and the success of EPCO, and will be integral to our success, due in part to his ability to identify and develop business opportunities, make strategic decisions and attract and retain key personnel. The loss of his leadership and involvement or the services of key members of our senior management team could have a material adverse effect on our business, results of operations, cash flows and financial condition.

Successful development of LNG import terminals outside our areas of operations could reduce the demand for our services.

Development of new, or expansion of existing, LNG facilities outside our areas of operations could reduce the need for customers to transport natural gas from supply basins connected to our pipelines. This could reduce the amount of gas transported by our pipelines for delivery off-system to other intrastate or interstate pipelines serving these customers. If we are not able to replace these volumes with volumes to other markets or other regions, throughput on our pipelines would decline which could have a material adverse effect on our financial condition, results of operations and ability to make distributions to our unitholders.

We do not own all of the land on which our pipelines and facilities are located, which could disrupt our operations.

We do not own all of the land on which our pipelines and facilities are located, and we are therefore subject to the risk of increased costs to maintain necessary land use. We obtain the rights to construct and operate certain of our pipelines and related facilities on land owned by third parties and governmental agencies for a specific period of time. Our loss of these rights, through our inability to renew right-of-way contracts or otherwise, or increased costs to renew such rights, could have a material adverse effect on our business, results of operations, financial condition and ability to make distributions to our unitholders.

Mergers among our customers or competitors could result in lower volumes being shipped on our pipelines, thereby reducing the amount of cash we generate.

Mergers among our existing customers or competitors could provide strong economic incentives for the combined entities to utilize systems other than ours and we could experience difficulty in replacing lost volumes and revenues. Because most of our operating costs are fixed, a reduction in volumes would result in not only a reduction of revenues, but also a decline in net income and cash flow of a similar magnitude, which would reduce our ability to meet our financial obligations and make distributions to our unitholders.

Terrorist attacks aimed at our facilities or our customers' facilities could adversely affect our business, results of operations, cash flows and financial condition.

Since the September 11, 2001 terrorist attacks on the United States, the United States government has issued warnings that energy assets, including our nation's pipeline infrastructure, may be the future target of terrorist organizations. Any terrorist attack on our facilities or pipelines or those of our customers could have a material adverse effect on our business.

Risks Inherent in an Investment in Us

Enterprise Products Partners and its affiliates, EPO and EPCO and its affiliates may compete with us, and business opportunities may be directed by contract to those affiliates prior to us under the administrative services agreement.

Our partnership agreement does not prohibit Enterprise Products Partners and its affiliates, EPO and EPCO and their affiliates, other than our general partner, from owning and operating natural gas and NGL pipelines and storage assets or engaging in businesses that otherwise compete directly or indirectly with us. In addition, Enterprise Products Partners, EPO and EPCO may acquire, construct or dispose of additional midstream energy or other natural gas assets in the future, without any obligation to offer us the opportunity to purchase or construct any of these assets.

Under the ASA, if any business opportunity, other than a business opportunity to acquire general partner interests and other related equity securities in a publicly traded partnership, is presented to EPCO and its affiliates, us and our general partner, EPO, Enterprise Products Partners and its general partner, or Enterprise GP Holdings and its general partner, then EPO will have the first right to pursue such opportunity for itself or, in its sole discretion, to affirmatively direct the opportunity to us. If EPO abandons the business opportunity for itself or for us, then Enterprise GP Holdings will have the second right to pursue such opportunity. If any business opportunity to acquire general partner interests and other related equity securities in a publicly traded partnership is presented, then Enterprise GP Holdings will have the right to pursue such opportunity before EPO is given the opportunity to pursue it for itself or to direct it to us. Accordingly, we are limited by contract in our ability to take certain business opportunities for our partnership. See Item 13 of this annual report.

Our general partner and its affiliates own a controlling interest in us and have conflicts of interest and limited fiduciary duties, which may permit them to favor their own interests to our detriment.

As of December 31, 2008, EPO directly owns a 0.7% general partner interest and approximately 74% of our outstanding common units and controls our general partner, which controls us. Although our general partner has a fiduciary duty to manage us in a manner beneficial to us and our unitholders, the directors and officers of our general partner have a fiduciary duty to manage it and our general partner in a manner beneficial to Enterprise Products Partners and its affiliates. Furthermore, certain directors and officers of our general partner may be directors or officers of affiliates of our general partner. Conflicts of interest may arise between Enterprise Products Partners and its affiliates, including our general partner, on the one hand, and us and our unitholders, on the other hand. As a result of these conflicts, our general partner may favor its own interests and the interests of its affiliates over the interests of our unitholders. These potential conflicts include, among others, the following situations:

§ Enterprise Products Partners, EPCO and their affiliates may engage in substantial competition with us on the terms set forth in the ASA.

§ Neither our partnership agreement nor any other agreement requires EPCO, Enterprise Products Partners, Enterprise GP Holdings and TEPPCO or their affiliates (other than our general partner) to pursue a business strategy that favors us. Directors and officers of EPCO and the general partners of Enterprise Products Partners, Enterprise GP Holdings and TEPPCO and their affiliates have a fiduciary duty to make decisions in the best interest of their shareholders or unitholders, which may be contrary to our interests.

§ Our general partner is allowed to take into account the interests of parties other than us, such as EPCO, Enterprise Products Partners, Enterprise GP Holdings and TEPPCO and their affiliates, in resolving conflicts of interest, which has the effect of limiting its fiduciary duty to our unitholders.

- § Some of the employees of EPCO who provide services to us also may devote significant time to the business of Enterprise Products Partners, Enterprise GP Holdings and TEPPCO, and will be compensated by EPCO for such services.

- § Our partnership agreement limits the liability and reduces the fiduciary duties of our general partner, while also restricting the remedies available to our unitholders for actions that, without these limitations, might constitute breaches of fiduciary duty. By purchasing common units, unitholders will be deemed to have consented to some actions and conflicts of interest that might otherwise constitute a breach of fiduciary or other duties under applicable law.

- § Our general partner determines the amount and timing of asset purchases and sales, operating expenditures, capital expenditures, borrowings, repayments of indebtedness, issuances of additional partnership securities and cash reserves, each of which can affect the amount of cash that is available for distribution to our unitholders.

- § Our general partner determines which costs, including allocated overhead, incurred by it and its affiliates are reimbursable by us.

- § EPO or TEPPCO may propose to contribute additional assets to us and, in making such proposal, the directors of those entities have a fiduciary duty to their unitholders and not to our unitholders.

- § Our partnership agreement does not restrict our general partner from causing us to pay it or its affiliates for any services rendered on terms that are fair and reasonable to us or entering into additional contractual arrangements with any of these entities on our behalf.

- § Our general partner intends to limit its liability regarding our contractual obligations.

- § Our general partner may exercise its rights to call and purchase all of our common units if, at any time, it and its affiliates own 80% or more of the outstanding common units.

- § Our general partner controls the enforcement of obligations owed to us by it and its affiliates, including the ASA.

- § Our general partner decides whether to retain separate counsel, accountants or others to perform services for us.

See Item 13 of this annual report for additional information regarding our relationships with EPCO and EPO.

We may be limited in our ability to consummate transactions, including acquisitions with affiliates of our general partner.

We will have inherent conflicts of interest with affiliates of our general partner, including Enterprise Products Partners and TEPPCO. These conflicts may cause the Audit, Conflicts and Governance Committees of these entities not to approve, or unitholders of these entities to dispute, any transactions that may be proposed or consummated between or among us and these affiliates. This may inhibit or prevent us from consummating transactions, including acquisitions, with them.

EPCO's employees may be subjected to conflicts in managing our business and the allocation of time and compensation costs between our business and the business of EPCO and its other affiliates.

We have no officers or employees and rely solely on officers of our general partner and employees of EPCO. Certain of our officers are also officers of EPCO and other affiliates of EPCO. These relationships may create conflicts of interest regarding corporate opportunities and other matters, and the resolution of any such conflicts may not always be in our or our unitholders' best interests. In addition, these overlapping officers allocate their time among us, EPCO and other affiliates of EPCO. These officers face potential conflicts regarding the allocation of their time, which may adversely affect our business, results of operations and financial condition.

We have entered into the ASA, which governs business opportunities among entities controlled by EPCO, which includes us and our general partner, Enterprise GP Holdings and its general partner, Enterprise Products Partners and its general partner and TEPPCO and its general partner. For information regarding how business opportunities are handled under the ASA within the EPCO group of companies, see Item 13 of this annual report.

We do not have an independent compensation committee, and aspects of the compensation of our executive officers and other key employees, including base salary, are not reviewed or approved by our independent directors. The determination of executive officer and key employee compensation could involve conflicts of interest resulting in economically unfavorable arrangements for us. For a discussion of our executive compensation policies and procedures, see Item 11 of this annual report.

An affiliate of EPO has the power to appoint and remove our directors and management.

Because EPO owns 100% of DEP GP, it has the ability to elect all the members of the board of directors of our general partner. Our general partner has control over all decisions related to our operations. Furthermore, the goals and objectives of EPO relating to us may not be consistent with those of a majority of the public unitholders.

Our general partner has a limited call right that may require unitholders to sell their common units at an undesirable time or price.

If at any time after December 8, 2010, our general partner and its affiliates own 80% or more of our outstanding common units, our general partner will have the right, which it may assign to any of its affiliates or to us, but not the obligation, to acquire all, but not less than all, of the common units held by unaffiliated persons at a price equal to the greater of:

§ the average of the daily closing prices of the common units over the 20 trading days preceding the date three days before notice of exercise of the call right is first mailed and

§ the highest price paid by our general partner or any of its affiliates for common units during the 90-day period preceding the date such notice is first mailed.

As a result, our unitholders may be required to sell their common units at a price that is less than the initial offering price or, because of the manner in which the purchase price is determined, at a price less than the then current market price of our common units. In addition, this call right may be exercised at an otherwise undesirable time or price and unitholders may not receive any return on their investment. Our unitholders may also incur a tax liability upon a sale of their common units. Our general partner is not obligated to obtain a fairness opinion regarding the value of the common units to be repurchased by it upon exercise of the call right. There is no restriction in our partnership agreement that prevents our general partner from issuing additional common units or other equity securities and exercising its call right. If our general partner exercised its call right, the effect would be to take us private and, if our common units were subsequently deregistered, we might no longer be subject to the reporting requirements of the Securities Exchange Act of 1934, as amended, or the “Exchange Act”. As of February 1, 2008, affiliates of Enterprise Products Partners, which owns our general partner, owned approximately 74.0% of our outstanding common units.

Our partnership agreement limits our general partner's fiduciary duties to unitholders and restricts the remedies available to unitholders for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty.

Our partnership agreement contains provisions that reduce the standards to which our general partner would otherwise be held by state fiduciary duty law. For example, our partnership agreement:

§ permits our general partner to make a number of decisions in its individual capacity, as opposed to in its capacity as our general partner. This entitles our general partner to consider only the interests and factors that it desires, and it has no duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or any limited partner. Examples include the exercise of its limited call right, its rights to vote or transfer our common units it owns, its registration rights and the determination of whether to consent to any merger or consolidation of the partnership, or amendment to the partnership agreement;

§ provides in the absence of bad faith by the Audit, Conflicts and Governance Committee or our general partner, the resolution, action or terms made, taken or provided in connection with a potential conflict of interest transaction will be conclusive and binding on all persons (including all partners) and will not constitute a breach of the partnership agreement or any standard of care or duty imposed by law;

§ provides the general partner shall not be liable to the partnership or any partner for its good faith reliance on the provisions of the partnership agreement to the extent it has duties, including fiduciary duties, and liabilities at law or in equity;

§ generally provides that affiliate transactions and resolutions of conflicts of interest not approved by the audit and conflicts committee of the board of directors of our general partner must be on terms no less favorable to us than those generally provided to or available from unrelated third parties or be "fair and reasonable" to us;

§ provides that it shall be presumed that the resolution of any conflicts of interest by our general partner or the audit, conflicts and governance committee was not made in bad faith, and in any proceeding brought by or on behalf of any limited partner or us, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption; and

§ provides that our general partner and its officers and directors will not be liable for monetary damages to us or our limited partners for any acts or omissions unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that the general partner or those other persons acted in bad faith or engaged in fraud or willful misconduct or, in the case of a criminal matter, acted with knowledge that the conduct was criminal.

By purchasing a common unit, a unitholder will become bound by the provisions of our partnership agreement, including the provisions described above.

Unitholders have limited voting rights and are not entitled to elect our general partner or its directors, which could lower the trading price of our common units.

Unlike the holders of common stock in a corporation, unitholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management's decisions regarding our business. Unitholders will have no right to elect our general partner or its board of directors on an annual or other continuing basis. The board of directors of our general partner, including the independent directors, is chosen entirely by its owners and not by the unitholders. Furthermore, even if our unitholders were dissatisfied with the performance of our general partner, they will, practically speaking, have a limited ability to remove our general partner. As a result of these limitations, the price at which our common units trade could be diminished because of the absence or reduction of a control premium in the trading price.

The vote of the holders of at least 66 2/3% of all outstanding common units is required to remove our general partner. Enterprise Products Partners and its affiliates currently own approximately 74.0% of our outstanding common units.

We may issue additional units without our unitholders' approval, which would dilute our unitholders' ownership interests.

At any time, we may issue an unlimited number of limited partner interests of any type without the approval of our unitholders. Our partnership agreement does not give unitholders the right to approve our issuance of equity securities ranking junior to our common units at any time. In addition, our partnership agreement does not prohibit the issuance by our subsidiaries of equity securities, which may effectively rank senior to our common units. The issuance by us of additional common units or other equity securities will have the following effects:

§ the ownership interest of unitholders immediately prior to the issuance will decrease;

§ the amount of cash available for distributions on each common unit may decrease;

§ the relative voting strength of each previously outstanding common unit may be diminished;

§ the ratio of taxable income to distributions may increase; and

§ the market price of our common units may decline.

Our partnership agreement restricts the voting rights of unitholders owning 20% or more of our common units.

Our partnership agreement restricts unitholders' voting rights by providing that any common units held by a person that owns 20% or more of any class of units then outstanding, other than our general partner, its affiliates, their transferees and persons who acquired such units with the prior approval of the board of directors of our general partner, cannot vote on any matter. Our partnership agreement also contains provisions limiting the ability of common unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting common unitholders' ability to influence the manner or direction of management.

We have a holding company structure in which our subsidiaries conduct our operations and own our operating assets, which may affect our ability to make distributions to our unitholders.

We are a partnership holding company and our operating subsidiaries conduct all of our operations and own all of our operating assets. We have no significant assets, other than the ownership interests, in our subsidiaries and joint ventures. As a result, our ability to make distributions to our unitholders depends on the performance of our subsidiaries and joint ventures and their ability to distribute funds to us. The ability of our subsidiaries and joint ventures to make distributions to us may be restricted by, among other things, the provisions of existing and future indebtedness, applicable state partnership and limited liability company laws and other laws and regulations, including FERC policies. For example, all cash flows from Evangeline are currently used to service its debt.

Affiliates of Enterprise Products Partners currently own a 34% minority equity interest in certain of our operating subsidiaries and a 49% equity interest in our remaining operating subsidiaries. These affiliates have a right of first refusal to acquire these subsidiaries or their material assets if we desire to sell them, other than inventory and other assets sold in the ordinary course of business. These rights may adversely affect our ability to dispose of these assets. In addition, our ownership interest in Mont Belvieu Caverns may be diluted, and the cash flow from our NGL Pipelines & Services segment may be reduced, if we do not contribute our proportionate share of certain future costs to fund expansion projects at Mont Belvieu Caverns.

We do not have the same flexibility as other types of organizations to accumulate cash and equity to protect against illiquidity in the future.

Unlike a corporation, our partnership agreement requires us to make quarterly distributions to our unitholders of all available cash reduced by any amounts of reserves for commitments and contingencies, including capital and operating costs and debt service requirements. The value of our common units and other limited partner interests may decrease in direct correlation with decreases in the amount we distribute per common unit. Accordingly, if we experience a liquidity problem in the future, we may not be able to issue more equity to recapitalize.

Cost reimbursements to EPCO and its affiliates will reduce cash available for distribution to our unitholders.

Prior to making any distribution on our common units, we will reimburse EPCO and its affiliates for all expenses they incur on our behalf, including allocated overhead. These amounts will include all costs incurred in managing and operating us, including costs for rendering administrative staff and support services to us, and overhead allocated to us by EPCO. The payment of these amounts, including allocated overhead, to EPCO and its affiliates could adversely affect our ability to make distributions to our unitholders. EPCO has sole discretion to determine the amount of these expenses. In addition, EPCO and its affiliates may provide other services to us for which we will be charged fees as determined by EPCO.

Unitholders may not have limited liability if a court finds that unitholder action constitutes control of our business.

The limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established in some of the states in which we do business. Unitholders could have unlimited liability for our obligations if a court or government agency determined that:

§ we were conducting business in a state, but had not complied with that particular state’s partnership statute; or

§ unitholders’ right to act with other unitholders to remove or replace our general partner, to approve some amendments to our partnership agreement or to take other actions under our partnership agreement constituted “control” of our business.

Unitholders may have liability to repay distributions.

Under certain circumstances, unitholders may have to repay amounts wrongfully returned or distributed to them. Under Section 17-607 of the Delaware Revised Uniform Limited Partnership Act (the “Delaware Act”), we may not make a distribution to our unitholders if the distribution would cause our liabilities to exceed the fair value of our assets. Liabilities to partners on account of their partnership interests and liabilities that are non-recourse to the partnership are not counted for purposes of determining whether a distribution is permitted. Delaware law provides that for a period of three years from the date of an impermissible distribution, limited partners who received the distribution and who knew at the time of the distribution that it violated Delaware law will be liable to the limited partnership for the distribution amount. A purchaser of common units who becomes a limited partner is liable for the obligations of the transferring limited partner to make contributions to the partnership that are known to such purchaser of common units at the time it became a limited partner and for unknown obligations if the liabilities could be determined from our partnership agreement.

Our general partner’s interest in us and the control of our general partner may be transferred to a third party without unitholder consent.

Our general partner may transfer its general partner interest to a third party in a merger or in a sale of all or substantially all of its assets without the consent of the unitholders. Furthermore, there is no restriction in our partnership agreement on the ability of DEP GP or EPO to transfer their equity interests in our general partner to a third party. The new equity owner of our general partner would then be in a position to replace the board of directors and officers of our general partner with their own choices and to influence the decisions taken by the board of directors and officers of our general partner.

Tax Risks to Common Unitholders

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

The anticipated after-tax benefit of an investment in our common units depends largely on our being treated as a partnership for federal income tax purposes. We have not requested, and do not plan to request, a ruling from the Internal Revenue Service ("IRS") on this matter.

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our income at the corporate tax rate, which is currently a maximum of 35%. Distributions to our unitholders could generally be taxed again as corporate distributions, and no income, gains, losses, deductions or credits could flow through to unitholders. Because a tax could be imposed upon us as a corporation, our cash available for distribution to our common unitholders could be substantially reduced. Thus, treatment of us as a corporation could result in a material reduction in the after-tax return to our common unitholders, likely causing a substantial reduction in the value of our common units.

Current law may change, causing us to be treated as a corporation for federal income tax purposes or otherwise subjecting us to a material amount of entity-level taxation. In addition, because of widespread state budget deficits and other reasons, several states (including Texas) are evaluating ways to enhance state-tax collections. For example, our operating subsidiaries are subject to a newly revised Texas franchise tax (the "Revised Texas Franchise Tax") on the portion of their revenue that is generated in Texas beginning for tax reports due on or after January 1, 2008. Specifically, the Revised Texas Franchise Tax is imposed at a maximum effective rate of 0.7% of the operating subsidiaries' gross revenue that is apportioned to Texas. If any additional state were to impose an entity-level tax upon us or our operating subsidiaries, the cash available for distribution to our common unitholders could be reduced.

The tax treatment of publicly traded partnerships or an investment in our common units could be subject to potential legislative, judicial or administrative changes and differing interpretations, possibly on a retroactive basis.

The present U.S. federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by administrative, legislative or judicial interpretation at any time. Any modification to the U.S. federal income tax laws and interpretations thereof could make it more difficult or impossible to meet the exception for us to be treated as a partnership for U.S. federal income tax purposes that is not taxable as a corporation, or Qualifying Income Exception, affect or cause us to change our business activities, affect the tax considerations of an investment in us, change the character or treatment of portions of our income and adversely affect an investment in our common units. For example, in response to certain recent developments, members of Congress are considering substantive changes to the definition of qualifying income under Section 7704(d) of the Internal Revenue Code. It is possible that these legislative efforts could result in changes to the existing U.S. tax laws that affect publicly traded partnerships, including us. Any modification to the U.S. federal income tax laws and interpretations thereof may or may not be applied retroactively. We are unable to predict whether any of these changes, or other proposals, will ultimately be enacted. Any such changes could negatively impact the value of an investment in our common units.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our common units each month based upon the ownership of our common units on the first day of each month, instead of on the basis of the date a particular common unit is transferred.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our common units each month based upon the ownership of our common units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The use of this proration method may not be permitted under existing Treasury regulations, and, accordingly, our counsel is unable to opine as to the validity of this method. If the IRS were to challenge this method or new Treasury regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

A successful IRS contest of the federal income tax positions we take may adversely impact the market for our common units, and the costs of any contests will be borne by our unitholders and our general partner.

The IRS may adopt positions that differ from the positions we take, even positions taken with advice of counsel. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we take. A court may not agree with some or all of the positions we take. Any contest with the IRS may materially and adversely impact the market for our common units and the price at which our common units trade. In addition, the costs of any contest with the IRS, principally legal, accounting and related fees, will be borne indirectly by our unitholders and our general partner.

Even if our common unitholders do not receive any cash distributions from us, they will be required to pay taxes on their share of our taxable income.

Common unitholders will be required to pay federal income taxes and, in some cases, state and local income taxes on their share of our taxable income whether or not they receive any cash distributions from us. Our common unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax liability resulting from their share of our taxable income.

Tax gain or loss on the disposition of our common units could be different than expected.

If a common unitholder sells common units, the unitholder will recognize a gain or loss equal to the difference between the amount realized and the unitholder’s tax basis in those common units. Prior distributions to a unitholder in excess of the total net taxable income a unitholder is allocated by us, which decreases the unitholder’s tax basis in a common unit, will, in effect, become taxable income to the unitholder if the common unit is sold at a price greater than the unitholder’s tax basis in that common unit, even if the price the unitholder receives is less than the unitholder’s original cost. A substantial portion of the amount realized, whether or not representing gain, may be ordinary income to a unitholder.

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

Investment in common units by tax-exempt entities, such as individual retirement accounts (known as IRAs), other retirement plans and non-U.S. persons raises issues unique to them. For example, virtually all of our income allocated to unitholders who are organizations exempt from federal income tax, including individual retirement accounts and other retirement plans, will be unrelated business taxable income and will be taxable to them. Distributions to non-U.S. persons will be reduced by withholding taxes at the highest applicable effective tax rate, and non-U.S. persons will be required to file United States federal income tax returns and pay tax on their share of our taxable income.

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

Because we cannot match transferors and transferees of common units, we will adopt depreciation and amortization positions that may not conform to all aspects of existing Treasury regulations. A successful IRS challenge to those positions could decrease the amount of tax benefits available to a common unitholder. It also could affect the timing of these tax benefits or the amount of gain from a sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to the common unitholder's tax returns.

Our common unitholders will likely be subject to state and local taxes and return filing requirements in states where they do not live as a result of an investment in our common units.

In addition to federal income taxes, our common unitholders will likely be subject to other taxes, such as state and local income taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we do business or own property. Our common unitholders will likely be required to file state and local income tax returns and pay state and local income taxes in some or all of these various jurisdictions. Further, they may be subject to penalties for failure to comply with those requirements. We own property or conduct business in Louisiana and Texas. We may own property or conduct business in other states or foreign countries in the future. It is the responsibility of the common unitholders to file all federal, state and local tax returns.

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

We will be considered to have terminated for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. Our termination would, among other things, result in the closing of our taxable year for all unitholders and could result in a deferral of depreciation deductions allowable in computing our taxable income.

Item 1B. *Unresolved Staff Comments.*

None.

Item 3. *Legal Proceedings.*

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 other significant litigation, pending or threatened, that may have a significant adverse effect on our financial position or results of operations.

Item 4. *Submission of Matters to a Vote of Unitholders.*

None.

PART II

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

We completed our initial public offering on February 5, 2007. Our common units are listed on the NYSE under the ticker symbol "DEP." As of February 2, 2009, there were approximately 40 unitholders of record of our common units. The following table presents the high and low sales prices for our common units during the periods indicated (as reported by the NYSE Composite Transaction Tape) and the amount, record date and payment date of the quarterly cash distributions we paid on each of our common units.

	Price Ranges		Cash Distribution History		
	High	Low	Per Unit	Record Date	Payment Date
2007					
1st Quarter (1)	$ 27.30	$ 22.10	$ 0.2440	April 30, 2007	May 9, 2007
2nd Quarter	29.55	24.80	0.4000	July 31, 2007	August 8, 2007
3rd Quarter	29.39	20.25	0.4100	October 31, 2007	November 7, 2007
4th Quarter	25.20	20.51	0.4100	January 31, 2008	February 7, 2008
2008					
1st Quarter	23.65	18.29	0.4100	April 30, 2008	May 7, 2008
2nd Quarter	21.29	18.04	0.4200	July 31, 2008	August 7, 2008
3rd Quarter	18.96	14.91	0.4200	October 31, 2008	November 12, 2008
4th Quarter	16.99	9.68	0.4275	January 30, 2009	February 9, 2009

(1) Our first cash distribution was prorated for the 55-day period from and including February 5, 2007 (the date of our initial public offering) through March 31, 2007 and based on a declared quarterly distribution of $0.40 per unit.

On December 8, 2008, we issued 37,333,887 Class B units to EPO in connection with the DEP II dropdown transaction. On February 9, 2009, the Class B units received a pro rated cash distribution of $0.1115 per unit for the distribution that Duncan Energy Partners paid with respect to the fourth quarter of 2008 for the 24-day period from December 8, 2008, the closing date of the DEP II dropdown transaction, to December 31, 2008. These units automatically converted on a one-for-one basis to common units on February 1, 2009.

The quarterly cash distributions per unit shown in the preceding table correspond to cash flows for the quarters indicated. The actual cash distributions (i.e., the payments made to our partners) occur within 45 days after the end of such quarter. We expect to fund our quarterly cash distributions to partners primarily with cash provided by operating activities. For additional information regarding our cash flows from operating activities, see "Liquidity and Capital Resources" included under Item 7 of this annual report. Although the payment of cash distributions is not guaranteed, we expect to continue to pay comparable cash distributions in the future.

We have no common units authorized for issuance under an equity compensation plan and we did not repurchase any of our common units during the year ended December 31, 2008.

Item 6. ***Selected Financial Data*****.**

The following table presents selected historical consolidated financial data of Duncan Energy Partners. See "Basis of Financial Statement Presentation" included under Item 1 of this annual report for information regarding the recast of our financial information for the years 2004 through 2007 in connection with the DEP II dropdown transaction.

Information regarding our consolidated results of operations and liquidity and capital resources can be found under Item 7 of this annual report. The selected financial data has been derived from our audited financial statements and should be read in conjunction with such statements included under Item 8 of this annual report. As presented in the table, amounts are in thousands (except per unit data).

	For the Year Ended December 31,				
	2008	2007	2006	2005	2004
Operating Results Data:					
Revenues	$ 1,598,068	$ 1,220,292	$ 1,263,028	$ 1,257,787	$ 818,197
Parent interest in income of subsidiaries (1)	7,369	19,973	--	--	--
Income from continuing operations	47,946	3,626	51,664	32,149	54,383
Net income	47,946	3,626	51,682	30,123	54,383
Net income (loss) allocations:					
Limited partners of Duncan Energy Partners	$ 27,850	$ 18,847	n/a	n/a	n/a
General partner of Duncan Energy Partners	492	385	n/a	n/a	n/a
Former owner of DEP II Midstream Businesses	19,604	(20,641)	(3,655)	(8,964)	(3,741)
Former owner of DEP I Midstream Businesses	--	5,035	55,337	39,087	58,124
Basic and diluted net income per unit	$ 1.22	$ 0.93	n/a	n/a	n/a
Cash distributions per common unit (2)	$ 1.68	$ 1.46	n/a	n/a	n/a
Financial position data (at period end):					
Total assets (3)	$ 4,594,724	$ 3,983,271	$ 3,798,353	$ 3,688,850	$ 3,657,803
Long-term debt (4)	484,250	200,000	n/a	n/a	n/a
Former owner’s equity in DEP II Midstream Businesses (5)	n/a	2,880,137	2,853,847	2,903,568	2,994,983
Former owner’s equity in DEP I Midstream Businesses (5)	n/a	n/a	725,797	527,767	509,719
Partners’ equity (6)	752,849	314,668	n/a	n/a	n/a
Total units outstanding at end of period (7)	57,677	20,302	n/a	n/a	n/a

(1) Represents EPO’s share of the earnings of the DEP I and DEP II Midstream Businesses following the dropdown of each set of businesses to Duncan Energy Partners. The DEP I dropdown transaction was effective February 1, 2007 for financial accounting and reporting purposes. The DEP II dropdown transaction was on December 8, 2008.

(2) Represents cash distributions declared by Duncan Energy Partners since its initial public offering in February 2007.

(3) Total assets have increased since our initial public offering due to capital spending.

(4) Represents the DEP I Revolving Credit Facility and DEP II Term Loan Agreement, as applicable, for the periods in which Duncan Energy Partners had borrowings outstanding under each agreement.

(5) Represents the net assets of the combined DEP I or DEP II Midstream Businesses (as applicable) prior to the date they were contributed to Duncan Energy Partners.

(6) Represents the limited and general partner capital accounts and related accumulated other comprehensive income of Duncan Energy Partners since February 2007.

(7) The amount presented for December 31, 2008 includes 37,334 Class B units that converted to common units on February 1, 2009.

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

For the years ended December 31, 2008, 2007 and 2006.

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

§ Cautionary Note Regarding Forward-Looking Statements.

§ Overview of Business, including information regarding our recent dropdown transactions.

§ Basis of Financial Statement Presentation.

§ General Outlook for 2009.

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

§ Parent Interest in Subsidiaries

§ 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, related party transactions, recent accounting pronouncements and similar disclosures.

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

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

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

Cautionary Note Regarding Forward-Looking Statements

This 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," "forecast," "intend," "could," "should," "will," "believe," "may," "potential" and similar expressions and statements regarding our plans and objectives for future operations, are intended to identify forward-looking statements. Although we and our general partner believe that 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 this annual report. 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.*

Overview of Business

Duncan Energy 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 "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 ("IPO") of 14,950,000 common units and acquired controlling interests in certain midstream energy businesses of Enterprise Products Operating LLC ("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 commonly-controlled affiliates.   Duncan Energy Partners is engaged in the business of (i) natural gas liquids ("NGL") transportation and fractionation; (ii) storage of NGL and petrochemical products; (iii) transportation of petrochemical products (iv) the gathering, transportation, storage of natural gas; and (v) the marketing of NGLs and natural gas.

At December 31, 2008, Duncan Energy Partners is owned 99.3% by its limited partners and 0.7% by its general partner, DEP Holdings, LLC ("DEP GP"), which is a wholly owned subsidiary of EPO. At December 31, 2008, EPO owned approximately 74% of Duncan Energy Partner's limited partner interests and 100% of its general partner. DEP GP is responsible for managing the business and operations of Duncan Energy Partners.   DEP Operating Partnership L.P. ("DEP OLP"), a wholly owned subsidiary of Duncan Energy Partners, conducts substantially all of Duncan Energy Partners' business. A private company affiliate, EPCO, Inc. ("EPCO"), provides all of Duncan Energy Partners' employees and certain administrative services to the partnership.

Enterprise Products Partners conducts substantially all of its business through EPO, a wholly owned subsidiary. Enterprise Products Partners is a publicly traded partnership, the common units of which are listed on the NYSE under the ticker symbol "EPD." The general partner of Enterprise Products Partners is owned by Enterprise GP Holdings L.P. ("Enterprise GP Holdings"), a publicly traded partnership the units of which are listed on the NYSE under the ticker symbol "EPE."

One of our principal advantages is our relationship with EPO and EPCO. 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 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 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.   See Item 13 of this annual report for additional information regarding our relationship with EPO and EPCO.

The following information summarizes the businesses acquired and consideration we provided in connection with the DEP I and DEP II dropdown transactions.

DEP I Dropdown Transaction

On February 5, 2007, EPO contributed a 66% controlling equity interest in each of the DEP I Midstream Businesses (defined below) to Duncan Energy Partners in a dropdown transaction (the "DEP I dropdown") made in connection with Duncan Energy Partners' IPO.   EPO retained the remaining 34% equity interest (as a Parent Interest) in each of the DEP I Midstream Businesses. The DEP I Midstream Businesses consist of (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").

As consideration for the equity interests in the DEP I Midstream Businesses and reimbursement for capital expenditures related to these businesses, Duncan Energy Partners distributed $260.6 million of the $290.5 million of net proceeds from its initial public offering to EPO, plus $198.9 million in borrowings under its initial credit facility (the "DEP I Revolving Credit Facility") and a net 5,351,571 common units. Prior to the DEP I dropdown transaction, we did not have any consolidated indebtedness.

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

§ Mont Belvieu Caverns owns 33 salt dome caverns located in Mont Belvieu, Texas, with an underground NGL and petrochemical storage capacity of approximately 100 MMBbls, and a brine system with approximately 20 MMBbls of above ground storage capacity and two brine production wells.

§ Acadian Gas gathers, transports, stores and markets natural gas in Louisiana utilizing over 1,000 miles of transmission, lateral and gathering pipelines with an aggregate throughput capacity of one billion cubic feet per day. Acadian Gas also owns a 49.51% equity interest in Evangeline Gas Pipeline Company, L.P. ("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 Duncan Energy Partners' Shoup and Armstrong NGL fractionation plants located in South Texas to Mont Belvieu, Texas. This pipeline commenced operations in January 2007.

Effective with the closing of our IPO and the DEP I dropdown transaction, changes were made to certain contracts that impact the post-dropdown results of operations of the DEP I Midstream Businesses. These changes are summarized as follows:

§ The fees Mont Belvieu Caverns charges EPO for underground storage services increased to market rates.

§ Storage well measurement gains and losses are retained by EPO rather than being allocated to Mont Belvieu Caverns.

§ Mont Belvieu Caverns makes a special allocation of its operational measurement gains and losses to EPO, which results in such gains and losses not impacting our net income or loss. However, operational measurement gains and losses continue to be a component of our gross operating margin amounts.

§ The transportation revenues recorded by Lou-Tex Propylene and Sabine Propylene decreased following our IPO due to the assignment of certain exchange agreements to us by EPO.

For additional information regarding these changes, see the discussions of our Mont Belvieu Storage complex and Lou-Tex and Sabine Propylene pipelines under Item 1 of this annual report.

DEP II Dropdown Transaction

On December 8, 2008, Duncan Energy Partners entered into a Purchase and Sale Agreement (the "DEP II Purchase Agreement") with EPO and Enterprise GTM Holdings L.P. ("Enterprise GTM," a wholly owned subsidiary of EPO). Pursuant to the DEP II Purchase Agreement, DEP OLP acquired 100% of the membership interests in Enterprise Holding III, LLC ("Enterprise III") from Enterprise GTM, thereby acquiring a 66% general partner interest in Enterprise GC, L.P. ("Enterprise GC"), a 51% general partner interest in Enterprise Intrastate L.P. ("Enterprise Intrastate") and a 51% membership interest in Enterprise Texas Pipeline LLC ("Enterprise Texas"). Collectively, we refer to Enterprise GC, Enterprise Intrastate and Enterprise Texas as the "DEP II Midstream Businesses." As with the DEP I dropdown, EPO was also the sponsor of this second dropdown transaction (the "DEP II dropdown"). Enterprise GTM retained the remaining partner and member interests (as a Parent Interest) in the DEP II Midstream Businesses.

As consideration for the Enterprise III membership interests, EPO received $280.5 million in cash and 37,333,887 Class B limited partner units having, at the time of issuance, a market value of $449.5 million from Duncan Energy Partners. The total value of the consideration provided to EPO and Enterprise GTM was $730.0 million. The cash portion of the consideration provided by Duncan Energy Partners in this dropdown transaction was derived from borrowings under a new bank credit agreement (the "DEP II Term Loan Agreement") and the proceeds of a $0.5 million equity offering to EPO. On February 9, 2009, the Class B units received a pro rated cash distribution of $0.1115 per unit for the distribution that Duncan Energy Partners paid with respect to the fourth quarter of 2008 for the 24-day period from December 8, 2008, the closing date of the DEP II dropdown transaction, to December 31, 2008. On February 1, 2009, the Class B units automatically converted on a one-for-one basis to common units on February 1, 2009.

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

§ Enterprise GC owns (i) the Shoup and Armstrong NGL fractionation facilities located in South Texas, (ii) a 1,020-mile NGL pipeline system located in South Texas and (iii) 944 miles of natural gas gathering pipelines located in South and West Texas. Enterprise GC's natural gas gathering pipelines include (i) the 272-mile Big Thicket Gathering System located in Southeast Texas, (ii) the 465-mile Waha system located in the Permian Basin of West Texas and (iii) the 207-mile TPC gathering system.

§ 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 6,547-mile Enterprise Texas natural gas pipeline system and leases the Wilson natural gas storage facility. The Enterprise Texas system, along with the Waha, TPC and Channel pipeline systems, comprise the Texas Intrastate System.

Generally, 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 Enterprise III (based on an initial defined investment of $730.0 million) and then to Enterprise GTM (based on an initial defined investment of $452.1 million) in amounts sufficient to generate an aggregate annualized return on their respective investments of 11.85%. Distributions in excess of these amounts will be distributed 98% to Enterprise GTM and 2% to Enterprise III. Income and loss of the DEP II Midstream Businesses are first allocated to Enterprise III and Enterprise GTM 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.

For information regarding EPO's Parent Interest in the DEP I and DEP II Midstream Businesses, see "Parent Interest in Subsidiaries" within this Item 7. See Item 13 of this annual report for additional information regarding our ongoing and extensive relationship with EPO, including certain contractual arrangements entered into as a result of the DEP I and DEP II dropdown transactions.

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 dropdown 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 dropdown transactions were 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 IPO, or February 5, 2007 (February 1, 2007 for financial accounting and reporting purposes).

References to the "former owners" of the DEP I and DEP II Midstream Businesses primarily refer to the direct and indirect ownership by EPO in these businesses prior to the related dropdown transactions. References to "Duncan Energy Partners" mean the registrant since February 5, 2007 and its consolidated subsidiaries, which include the DEP I and DEP II Midstream Businesses following their respective dropdown transaction dates. Generic references to "we," "us" and "our" mean the combined and/or consolidated businesses included in these financial statements for each reporting period.

Our consolidated financial statements include the accounts of Duncan Energy Partners and, prior to the DEP I and DEP II dropdown transactions, the assets, liabilities and operations contributed to us by EPO upon the closing of these dropdown 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 transactions 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, 2006 reflect the combined financial information of the DEP I and DEP II Midstream Businesses on a 100% basis. The results of operations and cash flows for these businesses 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, 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 dropdown 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 dropdown transaction is February 1, 2007. EPO's retained ownership in the DEP I Midstream Businesses (following the dropdown transaction) is presented in our consolidated financial statements as "Parent interest in Subsidiaries – DEP I Midstream Businesses."

§ 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 dropdown transaction. On December 8, 2008, the DEP II Midstream Businesses were contributed to Duncan Energy Partners in the DEP II dropdown 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 dropdown transaction) is presented in our consolidated financial statements as "Parent interest in Subsidiaries – DEP II Midstream Businesses."

Effective with the fourth quarter of 2008, our segment information has been recast in connection with the DEP II dropdown transaction.

General Outlook for 2009

The current global recession and financial crisis have impacted energy companies generally. The recession and related slowdown in economic activity has reduced demand for energy and related products, which in turn has generally led to significant decreases in the prices of crude oil, natural gas and NGLs. The financial crisis has resulted in the effective insolvency, liquidation or government intervention for a number of financial institutions, investment companies, hedge funds and highly leveraged industrial companies. This has had an adverse impact on the prices of debt and equity securities that has generally increased the cost and limited the availability of debt and equity capital.

Commercial Outlook

In 2008, there was significant volatility in the prices of refined products, crude oil, natural gas and NGLs. For example, the price of West Texas Intermediate crude oil ranged from a high near $147 per barrel in mid-2008 to $35 per barrel in January 2009; while the price of natural gas at the Henry Hub ranged from a high of over $13.00 per MMBtu in mid-2008 to $5.00 per MMBtu in January 2009. On a composite basis, the average price of NGLs declined from $1.68 per gallon for the third quarter of 2008 to $0.74 per gallon for the fourth quarter of 2008. The decrease in energy commodity prices, combined with higher costs of capital, has led many crude oil and natural gas producers to reconsider their drilling budgets for 2009. As a midstream energy company, we provide services for producers and consumers of natural gas, NGLs, crude oil and certain petrochemicals. The products that we process, sell or transport are principally used as fuel for residential, agricultural and commercial heating; feedstocks in petrochemical manufacturing; and in the production of motor gasoline.

The decrease in energy commodity prices has caused many oil and natural gas producers, which include many of our customers, to reduce their drilling budgets in 2009. This has resulted in a substantial reduction in the number of drilling rigs operating in the United States as surveyed by Baker Hughes Incorporated. The U.S. operating rig count decreased from a peak of 2,031 rigs in September 2008 to approximately 1,300 in February 2009. We expect oil and gas producers in our operating areas to reduce their drilling activity to varying degrees, which may lead to lower crude oil, natural gas and NGL production growth in the near term and, as a result, lower transportation, processing and marketing volumes for us than would have otherwise been the case.

The recession has reduced demand for midstream energy services and products by industrial customers. In the fourth quarter of 2008, the petrochemical industry experienced a dramatic destocking of inventories, which reduced demand for purity NGL products such as ethane, propane and normal butane. We expect that petrochemical demand will strengthen in early 2009 and have starting seeing signs of such demand through February 2009 as petrochemical customers have begun to restock their depleted inventories. This trend is also evidenced by slightly higher operating rates of U.S. ethylene crackers, which averaged approximately 70% of capacity in February 2009 as compared to 56% in December 2008. Four additional ethylene crackers were expected to recommence operations in February 2009. The average utilization rate for ethylene crackers in 2008 was approximately 80%. Based on currently available information, we expect that the operating rates of U.S. ethylene crackers will approximate 80% of capacity in 2009. We expect that crude oil prices will rebound from recent lows in the second half of 2009. As a result, we believe the petrochemical industry will continue to prefer NGL feedstocks over crude-based alternatives such as naphtha. In general, when the price of crude oil rises relative to that of natural gas, NGLs become more attractive as a source of feedstocks for the petrochemical industry.

Liquidity Outlook

Debt and equity capital markets have also experienced significant recent volatility. The major U.S. and international equity market indices experienced significant losses in 2008, including losses of approximately 38% and 34% for the S&P 500 and Dow Jones Industrial Average, respectively. Likewise, the Alerian MLP Index, which is a recognized major index for publicly traded partnerships, lost approximately 42% of its value. The contraction in credit available to and investor redemptions of holdings in certain investment companies and hedge funds exacerbated the selling pressure and volatility in both the debt and equity capital markets. This has resulted in a higher cost of debt and equity capital for the public and private sector. Near term demand for equity securities through follow on offerings, including our common units, may be reduced due to the recent problems encountered by investment companies and hedge funds, both of which significantly participated in equity offerings over the past few years.

A few of our customers have experienced severe financial problems leading to a significant impact on their creditworthiness. These financial problems are rooted in various factors including the significant use of debt, current financial crises, economic recession and changes in commodity prices. We are working to implement, to the extent allowable under applicable contracts, tariffs and regulations, prepayments and other security requirements, such as letters of credit, to enhance our respective credit position relating to amounts owed to us by certain customers. We cannot provide assurance that one or more of our customers will not default on their obligations to us or that such a default or defaults will not have a material adverse effect on our consolidated financial position, results of operations, or cash flows; however, we believe that we have provided adequate allowances for such customers.

Cash flows from our operating businesses are expected to be stable during 2009, especially in light of the distribution provisions of our DEP II Midstream Businesses. We expect our proactive approach to funding partnership needs, combined with sufficient trade credit to operate our businesses efficiently and available borrowing capacity under our DEP I Revolving Credit Facility, to provide us with adequate liquidity and capital resources during 2009. In addition, we expect to meet our financial covenant obligations under loan agreements in 2009.

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 senior management in deciding how to allocate capital resources among business segments. We believe that investors benefit from having access to the same financial measures that our management uses in evaluating segment results. The GAAP financial measure most directly comparable to total segment gross operating margin is operating income. Our non-GAAP financial measure of total segment gross operating margin should not be considered as an alternative to GAAP operating income.

We define total segment gross operating margin as consolidated operating income before (i) depreciation, amortization and accretion expense; (ii) gains and losses on asset sales and related transactions; and (iii) general and administrative expenses. 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 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.

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. NGL throughput volumes for the South Texas NGL System increased in 2007 when the DEP South Texas NGL pipeline (a component of the South Texas NGL System) became operational in January 2007.

	For the Year Ended December 31,		
	2008	**2007**	**2006**
Natural Gas Pipelines & Services, net:			
Natural gas throughput volumes (BBtus/d)			
Texas Intrastate System	4,021	3,550	3,586
Acadian Gas System:			
Transportation volumes	378	416	434
Sales volumes (1)	331	308	325
Total natural gas throughput volumes	4,730	4,274	4,345
NGL Pipelines & Services, net:			
NGL throughput volumes (MBPD)			
South Texas NGL System - Pipelines	126	124	57
NGL Fractionation volumes (MBPD)			
South Texas NGL System - Fractionators	80	72	66
Petrochemical Services, net:			
Propylene throughput volumes (MBPD)			
Lou-Tex Propylene Pipeline	25	25	27
Sabine Propylene Pipeline	10	12	10
Total propylene throughput volumes	35	37	37

(1) Includes average net sales volumes for Evangeline of 50 BBtus/d for each of the years ended December 31, 2008, 2007 and 2006, respectively.

Comparison of Results of Operations

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

	For the Year Ended December 31,		
	2008	2007	2006
Revenues	$ 1,598,068	$ 1,220,292	$ 1,263,028
Operating costs and expenses	1,512,806	1,170,942	1,200,872
General and administrative costs	18,305	13,116	10,227
Equity in income of Evangeline	896	182	958
Operating income	67,853	36,416	52,887
Interest expense			
Parent interest in income of the DEP I Midstream Businesses	(11,354)	(19,973)	--
Parent interest in income of the DEP II Midstream Businesses	3,985	--	--
Net income	47,946	3,626	51,682

For information regarding our Parent interest amounts, see the section titled "Parent Interest in Subsidiaries" within this Item 7.

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

	For the Year Ended December 31,		
	2008	2007	2006
Natural Gas Pipelines & Services	$ 159,022	$ 122,486	$ 123,983
NGL Pipelines & Services	82,879	87,925	59,393
Petrochemical Services	11,105	14,349	35,710
Total segment gross operating margin	$ 253,006	$ 224,760	$ 219,086

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 of 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 thousands):

	For the Year Ended December 31,		
	2008	2007	2006
Natural Gas Pipelines & Services:			
Sales of natural gas	$ 1,029,835	$ 742,898	$ 815,797
Natural gas transportation services	317,107	263,959	241,548
Natural gas storage services	8,361	1,475	6,155
Total segment revenues	$ 1,355,303	$ 1,008,332	$ 1,063,500
NGL Pipelines & Services:			
Sales of NGLs	$ 47,899	$ 40,338	$ 36,263
Sales of other products	15,017	10,776	11,201
NGL and petrochemical storage services	87,429	68,912	56,791
NGL fractionation services	32,370	30,253	29,630
NGL transportation services	43,605	42,542	23,748
Other services	2,242	1,748	2,808
Total segment revenues	$ 228,562	$ 194,569	$ 160,441
Petrochemical Services:			
Propylene transportation services	$ 14,203	$ 17,391	$ 39,087
Total consolidated revenues	$ 1,598,068	$ 1,220,292	$ 1,263,028

A related party, Evangeline, is our largest customer and accounted for 22.7%, 21.7% and 22.0% of our consolidated revenues in 2008, 2007 and 2006, respectively. Related party revenues from Evangeline are attributable to the sale of natural gas and are presented in our Natural Gas Pipelines & Services business segment. Sales to Evangeline totaled $362.9 million, $264.2 million and $277.7 million for the years ended December 31, 2008, 2007 and 2006, respectively.

Our largest third party customer was Exxon Mobil Corporation ("Exxon Mobil") and affiliates, which accounted for 10.0%, 7.6% and 7.3% of our consolidated revenues in 2008, 2007 and 2006, respectively. The majority of our revenues from Exxon Mobil are derived from the sale and transportation of natural gas and are also presented in our Natural Gas Pipelines & Services business segment. Sales to Exxon Mobil totaled $159.2 million, $93.2 million and $92.0 million for the years ended December 31, 2008, 2007 and 2006, respectively.

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 $298.7 million year-to-year increase in revenues from our marketing activities, primarily from the sale of natural gas and NGLs. Revenues from our natural gas pipeline and storage businesses increased $60.0 million year-to-year primarily due to higher pipeline transportation fees and volumes during 2008 relative to 2007. Revenues from NGL fractionation, transportation and storage services increased $21.7 million year-to-year primarily due to increased NGL storage activity and higher storage fees. Revenues from propylene transportation decreased $3.2 million 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 $341.9 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 $292.9 million year-to-year as a result of an increase in volumes and energy commodity prices. Costs and expenses from our natural gas pipeline and storage businesses increased $31.1 million year-to-year primarily due to higher natural gas prices and repair and maintenance expenses during 2008 relative to 2007. Costs and expenses from NGL fractionation, transportation and storage increased $26.5 million year-to-year primarily due to higher operating costs and expenses from our Mont Belvieu Storage complex.

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 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 income from continuing operations (before Parent interest) 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 $167.4 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 market price of natural gas (as measured at Henry Hub) 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. Our determination of the weighted-average indicative market price for NGLs is based on U.S. Gulf Coast prices for such products at Mont Belvieu, Texas, which is the primary industry hub for domestic NGL production.

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. In addition, the level of commodity prices affects the revenues and costs and expenses we record in connection with aggregating and bundling natural gas gathering services provided to certain small producers connected to our Texas Intrastate System. Under these arrangements, we typically purchase natural gas at the wellhead based on an index price less a pricing differential and resell the natural gas at a pipeline interconnect based on the same index price. The intent of these arrangements is to earn a fee for our natural gas gathering services; however, changes in the price of natural gas impacts our revenues and costs and expenses.

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 dropdown transaction in December 2008 and a decrease in the amount of interest capitalized during 2008 relative to 2007. We borrowed $282.3 million under the DEP II Term Loan Agreement on December 8, 2008 to fund $280.5 million of cash consideration paid to EPO for interests in the DEP II Midstream Businesses and the remainder for general partnership purposes. The DEP II Term Loan matures in December 2011. For the period in which borrowings were outstanding under the DEP II Term Loan in December 2008, the weighted-average variable interest rate charged was 2.93%.

Parent interest in the income of subsidiaries reflects a net earnings allocation of $7.4 million for 2008 versus $20.0 million for 2007. For an explanation of our Parent interest amounts, see "Parent Interest in Subsidiaries" within this Item 7.

As a result of items noted in the previous paragraphs, our consolidated net income increased $44.3 million year-to-year to $47.9 million for 2008 compared to $3.6 million for 2007.

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 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. Gross operating margin from our Mont Belvieu Storage complex decreased $2.7 million year-to-year. Results for this business reflect operational measurement losses of $6.8 million for 2008 compared to operational measurement gains of $4.5 million for 2007. Although operational measurement gains and losses are included in gross operating margin, they are allocated to EPO through Parent interest in income of Mont Belvieu Caverns; thus, such gains and losses are not included in our net income or loss. Revenues from our Mont Belvieu storage complex increased $18.3 million year-to-year due to higher volumes and excess throughput and base reservation fees. Operating costs and expenses, excluding operational measurement gains and losses allocated to EPO, increased $9.7 million year-to-year primarily due to higher expenses for power-related costs, repair and maintenance and salaries and employee costs. This includes $0.3 million of property damage repair expenses during 2008 resulting from Hurricane Ike.

Gross operating margin from our South Texas NGL System decreased $2.3 million year-to-year. Pipeline transportation volumes on this system increased to 126 MBPD during 2008 from 124 MBPD during 2007. NGL fractionation volumes were 80 MBPD during 2008 compared to 72 MBPD during 2007. System revenues increased $3.1 million year-to-year attributable to higher volumes during 2008 relative to 2007. Operating costs and expenses increased $5.4 million year-to-year primarily due to higher expenses for repair and maintenance and pipeline integrity. This includes $0.1 million of property damage repair expenses during 2008 resulting from Hurricane 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.

Comparison of Year Ended December 31, 2007 with Year Ended December 31, 2006

Revenues for 2007 were $1.22 billion compared to $1.26 billion for 2006. The $42.7 million year-to-year decrease in our revenues is primarily due to lower natural gas sales volumes and prices during 2007 relative to 2006. These factors accounted for a $69.2 million year-to-year decrease in revenues, from our marketing activities, primarily from the sale of natural gas. Revenues from our natural gas pipeline and storage businesses increased $17.7 million year-to-year primarily due to higher volumes of natural gas sold under aggregating and bundling agreements with producers and an increase in pipeline transportation fees during 2007 relative to 2006. Revenues from NGL fractionation, transportation and storage services increased $31.5 million year-to-year primarily due to revenues from the DEP South Texas NGL Pipeline, which became operational during January 2007. Revenues from propylene transportation decreased $21.7 million year-to-year due to lower transportation fees in 2007 relative to 2006.

Operating costs and expenses were $1.17 billion for 2007 compared to $1.20 billion for 2006. The $29.9 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 marketing activities decreased $68.4 million year-to-year as a result of a decrease in volumes and natural gas prices. Costs and expenses from our natural gas pipeline and storage businesses increased $17.3 million year-to-year primarily due to an increase in the volumes of natural gas we purchased at the wellhead in connection with gathering contracts on our Texas Intrastate System. Collectively, all other costs and expenses increased $21.2 million primarily due to higher depreciation expenses during 2007 relative to 2006 as a result of new assets (e.g., the DEP South Texas NGL Pipeline) and capital projects on existing assets.

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 $6.86 per

MMBtu for 2007 versus $7.24 per MMBtu for 2006. The weighted-average indicative market price for NGLs was $1.19 per gallon during 2007 versus $1.00 per gallon during 2006.

General and administrative costs were $13.1 million for 2007 compared to $10.2 million for 2006. Equity earnings from Evangeline decreased $0.8 million year-to-year.

Operating income for 2007 was $36.4 million compared to $52.9 million for 2006. Collectively, the aforementioned changes in revenues, costs and expense and equity earnings contributed to the $16.5 million year-to-year decrease in operating income. Interest expense for 2007 includes $9.3 million attributable to debt that we incurred at the time of our initial public offering. In addition, net income for 2007 includes $20.0 million of expense for Parent interest in the income of the DEP I Midstream Businesses.

As a result of the items noted in the previous paragraphs, our net income decreased $48.1 million year-to-year to $3.6 million in 2007 compared to $51.7 million in 2006. Net income for 2006 includes the recognition of non-cash amounts related to a cumulative effect of change in accounting principle. For additional information regarding the cumulative effect of change in accounting principle we recorded in 2006, see "Other Items" below.

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 $122.5 million for 2007 compared to $124.0 million for 2006, a $1.5 million decrease year-to-year. Total natural gas throughput volumes were 4,274 BBtus/d during 2007 compared to 4,345 BBtus/d during 2006. Segment gross operating margin attributable to our Texas Intrastate System decreased $8.4 million year-to-year primarily due to higher expenses for repair and maintenance and pipeline integrity during 2007 relative to 2006.

Gross operating margin attributable to our Acadian Gas system decreased $6.6 million year-to-year, of which $2.6 million is attributable to our collection of a contingent asset during 2006. The remainder of the year-to-year decrease in segment gross operating margin is primarily due to (i) lower natural gas sales margins and volumes and (ii) higher repair and maintenance costs during 2007 compared to 2006. Equity earnings from our investment in Evangeline decreased $0.8 million year-to-year due to lower natural gas sales margins and higher maintenance costs during 2007 relative to 2006.

Segment gross operating margin from our Wilson natural gas storage facility increased $14.4 million year-to-year primarily due to lower repair costs in 2007 relative to 2006 and a loss on the sale of cushion gas during 2006. Due to mechanical issues at our Wilson facility, three storage wells were taken out of service in the second quarter of 2006 for repairs and remained out of service during 2007 and a portion of 2008.

NGL Pipelines & Services. Gross operating margin from this business segment was $87.9 million for 2007 compared to $59.4 million for 2006, a $28.5 million year-to-year increase. Segment gross operating margin attributable to Mont Belvieu Caverns increased $14.8 million year-to-year primarily due to contract changes with EPO that were executed in connection with our initial public offering. Revenues associated with Mont Belvieu Caverns increased $12.3 million year-to-year primarily due to higher excess storage and throughput fees and brine production revenues. Changes in our contracts with EPO resulted in a $9.2 million increase in storage revenues for 2007 compared to 2006. Historically, such intercompany charges had been below market and eliminated in the consolidated revenues and costs and expenses of Enterprise Products Partners. Operating costs and expenses associated with Mont Belvieu Caverns decreased $2.0 million year-to-year primarily due to reduced measurement losses, which were partially offset by higher maintenance and integrity management expenses during 2007 relative to 2006.

Segment gross operating margin from our South Texas NGL System increased $14.9 million year-to-year. Pipeline transportation volumes on this system increased to 124 MBPD during 2007 from 57

MBPD during 2006. NGL fractionation volumes were 72 MBPD during 2007 compared to 66 MBPD during 2006. Gross operating margin for 2007 includes $21.1 million generated by the DEP South Texas NGL Pipeline that we placed in service during January 2007. The DEP South Texas NGL Pipeline contributed 73 MBPD of volumes during 2007. Gross operating margin for the remainder of the South Texas NGL System decreased $6.2 million year-to-year attributable to lower pipeline transportation volumes and fees and higher expenses for repair and maintenance.

Segment gross operating margin from our Big Thicket Gathering System and related NGL marketing activities decreased $1.2 million year-to-year primarily due to lower NGL sales margins and higher maintenance expenses during 2007 relative to 2006.

Petrochemical Services. Gross operating margin from this business segment was $14.3 million for 2007 compared to $35.7 million for 2006. Petrochemical transportation volumes were 37 MBPD during both 2007 and 2006. The $21.4 million year-to-year decrease in segment gross operating margin is primarily due to lower transportation revenues as a result of EPO assigning its third party product exchange agreements to us in connection with our initial public offering. Accordingly, the transportation fees we currently receive for services provided on our Lou-Tex Propylene and Sabine Propylene Pipelines are less than the fees we received from EPO prior to February 2007.

Parent Interest in Subsidiaries

Parent interest in Subsidiaries – DEP I Midstream Businesses

Following completion of the DEP I dropdown transaction effective February 1, 2007, we account for EPO's 34% equity interests in the DEP I Midstream Businesses as "Parent interest" in a manner similar to minority interest. Under this method of presentation, all revenues and expenses of the DEP I Midstream Businesses are included in income from continuing operations, and EPO's share (as Parent) of the income of the DEP I businesses is shown as an adjustment in deriving our net income. In addition, EPO's share of the net assets of the DEP I Midstream Businesses is presented as Parent interest on our consolidated balance sheet.

The DEP I Midstream Businesses distribute their income and operating cash flows in accordance with the following sharing ratios: 66% to Duncan Energy Partners and 34% to EPO. With the exception of special funding arrangements by EPO in connection with the assets owned by South Texas NGL and Mont Belvieu Caverns (as described below), Duncan Energy Partners and EPO make contributions to the DEP I Midstream Businesses in accordance with the previously noted sharing ratios.

Effective with the closing of our IPO in February 2007, we entered into an Omnibus Agreement (see Item 13 of this annual report) with EPO. Under the Omnibus Agreement, EPO agreed to make additional cash contributions to South Texas NGL and Mont Belvieu Caverns to fund 100% of project costs in excess of (i) $28.6 million of estimated costs to complete the Phase II expansion of the DEP South Texas NGL pipeline (a component of our South Texas NGL System) and (ii) $14.1 million of estimated costs for additional Mont Belvieu brine production capacity and above-ground storage reservoir projects. These two projects were in progress at the time of our IPO and the estimated costs of each (as noted above) were based on information available at the time of the DEP I dropdown transaction. EPO made cash contributions to our subsidiaries of $32.5 million and $9.9 million in connection with the Omnibus Agreement during the years ended December 31, 2008 and 2007, respectively. The majority of these contributions related to funding the Phase II expansion costs of the DEP South Texas NGL pipeline. Since the two noted projects were completed in 2008, no additional contributions are expected by EPO in the future with respect to these assets. EPO will not receive an increased allocation of earnings or cash flows as a result of these contributions to South Texas NGL and Mont Belvieu Caverns.

The Mont Belvieu Caverns' LLC Agreement (the "Caverns LLC Agreement") states that if Duncan Energy Partners elects not to 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 projects from EPO within 90 days of such projects being placed in service. EPO made cash contributions of $99.5 million and $38.1 million under the Caverns LLC Agreement during the years ended December 31, 2008 and 2007, respectively, to fund 100% of certain storage-related projects sponsored by EPO's NGL marketing activities. At present, Mont Belvieu Caverns is not expected to generate any identifiable incremental cash flows in connection with these projects; thus, the sharing ratio for Mont Belvieu Caverns is not expected to change from the current sharing ratio of 66% for Duncan Energy Partners and 34% for EPO. We expect additional contributions of approximately $27.5 million from EPO to fund such projects in 2009. The constructed assets will be the property of Mont Belvieu Caverns.

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. For the two-month period in 2008 covered by the amendment, EPO was allocated (through Parent interest) depreciation expense of $1.0 million related to such projects.

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. Effective with the closing of our IPO, EPO has been allocated (through Parent interest) all operational measurement gains and losses relating to Mont Belvieu Caverns' underground storage activities. As a result, 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 neither affect our net income nor have a significant impact on us with respect to the timing of our net cash flows provided by operating activities. Accordingly, we have not established a reserve for operational measurement losses on our balance sheet.

The following table presents our calculation of "Parent interest in income – DEP I Midstream Businesses" for the eleven months ended December 31, 2007 (dollars in thousands). We allocated income of $20.0 million to EPO as Parent for the eleven month period (February 1 to December 31) following February 1, 2007, the effective date of the DEP I dropdown transaction for accounting purposes.

Mont Belvieu Caverns:		
Mont Belvieu Caverns' net income (before special allocation of operational measurement gains and losses)	$ 22,165	
Deduct operational measurement gain allocated to Parent	(4,537)	$ 4,537
Remaining Mont Belvieu Caverns' net income to allocate to partners	17,628	
Multiplied by Parent 34% interest in remaining net income	x 34%	
Mont Belvieu Caverns' net income allocated to Parent	$ 5,994	5,994
Acadian Gas net income multiplied by Parent 34% interest		1,158
Lou-Tex Propylene net income multiplied by Parent 34% interest		2,552
Sabine Propylene net income multiplied by Parent 34% interest		373
South Texas NGL net income multiplied by Parent 34% interest		5,359
Parent interest in income – DEP I Midstream Businesses (allocated income)		$ 19,973

The following table presents our calculation of "Parent interest in income – DEP I Midstream Businesses" for the year ended December 31, 2008 (dollars in thousands). With respect to the DEP I Midstream Businesses, we allocated income of $11.4 million to EPO as Parent in 2008.

Mont Belvieu Caverns:		
Mont Belvieu Caverns' net income (before special allocation of operational measurement gains and losses)	$ 15,514	
Add operational measurement loss allocated to Parent	6,831	$ (6,831)
Add depreciation expense related to fully fund projects allocated to Parent	984	(984)
Remaining Mont Belvieu Caverns' net income to allocate to partners	23,329	
Multiplied by Parent 34% interest in remaining net income	x 34%	
Mont Belvieu Caverns' net income allocated to Parent	$ 7,932	7,932
Acadian Gas net income multiplied by Parent 34% interest		3,622
Lou-Tex Propylene net income multiplied by Parent 34% interest		2,174
Sabine Propylene net income multiplied by Parent 34% interest		382
South Texas NGL net income multiplied by Parent 34% interest		5,059
Parent interest in income – DEP I Midstream Businesses (allocated income)		$ 11,354

The following table provides a reconciliation of the amounts presented as "Parent interest in Subsidiaries – DEP I Midstream Businesses" on our consolidated balance sheets at December 31, 2007 and 2008 (dollars in thousands).

Fiscal year 2007 transactions:	
Retention by Parent of 34% ownership interest in DEP I Midstream Businesses on February 1, 2007	$ 252,292
Net income of DEP I Midstream Businesses allocated to EPO as Parent – February 1 to December 31, 2007	19,973
Contributions by EPO to DEP I Midstream Businesses – February 1 to December 31, 2007:	
Contributions from EPO to Mont Belvieu Caverns in connection with capital projects in which EPO is funding 100% of the expenditures in accordance with the Mont Belvieu Caverns' LLC Agreement, including accrued receivables at December 31, 2007 (see Note 14)	49,524
Contributions from EPO to Mont Belvieu Caverns and South Texas NGL in connection with capital Projects in which EPO is funding 100% of the expenditures in excess of certain thresholds in Accordance with the Omnibus Agreement, including accrued receivables at December 31, 2007 (see Note 14)	10,952
Other contributions by EPO to the DEP I Midstream Businesses	57,035
Cash distributions to EPO by Mont Belvieu Caverns for operational measurement gains	(4,537)
Cash distributions to EPO of operating cash flows of DEP I Midstream Businesses	(26,901)
Other	(3,209)
December 31, 2007 balance	355,129
Net income of DEP I Midstream Businesses allocated to EPO as Parent	11,354
Contributions by EPO to DEP I Midstream Businesses:	
Contributions from EPO to Mont Belvieu Caverns in connection with capital projects in which EPO is funding 100% of the expenditures in accordance with the Mont Belvieu Caverns' LLC Agreement, including accrued receivables at December 31, 2008 (see Note 14)	88,076
Contributions from EPO to Mont Belvieu Caverns and South Texas NGL in connection with capital Projects in which EPO is funding 100% of the expenditures in excess of certain thresholds in Accordance with the Omnibus Agreement, including accrued receivables at December 31, 2008 (see Note 14)	31,414
Contributions by EPO in connection with operational measurement losses of Mont Belvieu Caverns	6,831
Other contributions by EPO to the DEP I Midstream Businesses	29,669
Cash distributions to EPO of operating cash flows of DEP I Midstream Businesses	(44,105)
December 31, 2008 balance	$ 478,368

Parent interest in Subsidiaries – DEP II Midstream Businesses

Following completion of the DEP II dropdown transaction on December 8, 2008, we account for EPO's equity interests in the DEP II Midstream Businesses as Parent interest. All revenues and expenses of the DEP II Midstream Businesses are included in income from continuing operations, and EPO's share (as Parent) of the income of the DEP II Midstream Businesses is shown as an adjustment in deriving our net income. In addition, EPO's share of the net assets of the DEP II Midstream Businesses is presented as Parent interest on our consolidated balance sheet.

The total value of the consideration we provided in the DEP II dropdown transaction was $730.0 million, which value was agreed to after taking into account both our fixed annual return and our limited upside potential in the future cash flows of the DEP II Midstream Businesses.The total fair value of the DEP II Midstream Businesses was approximately $3.2 billion. As a result, the $730.0 million in consideration represented the acquisition of 22.6% of the then existing capital accounts of the DEP II Midstream Businesses. EPO retained the remaining 77.4% of the then existing capital accounts. 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, the DEP II dropdown transaction documents provide 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 Enterprise III (based on an initial defined investment of $730.0 million, the "Enterprise III Distribution Base") and then to Enterprise GTM (based on an initial defined investment of $452.1 million, the "Enterprise GTM Distribution Base") in amounts sufficient to generate an aggregate annualized fixed return on their respective distribution bases of 11.85% (see below). Distributions in excess of these amounts will be distributed 98% to Enterprise GTM and 2% to Enterprise III.

The initial fixed annual return is 11.85%. This initial fixed return was determined by the parties based on our estimated weighted-average cost of capital at December 8, 2008, plus 1.0%. The fixed return will be increased by 2.0% each calendar year after 2009. For example, assuming no other adjustments, the fixed return for 2010 would be 102% of 11.85%, or 12.087%. The initial Enterprise III Distribution Base and the Enterprise GTM Distribution Base amounts represent negotiated values between us and EPO. If Enterprise III participates in an expansion project in any of the DEP II Midstream Businesses, it may request an incremental adjustment to the then-applicable fixed return to reflect Duncan Energy Partners' weighted-average cost of capital associated with such contribution. To the extent that Enterprise III and/or Enterprise GTM make capital contributions to fund expansion capital projects at any of 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.

Income and loss of the DEP II Midstream Businesses is first allocated to Enterprise III and Enterprise GTM 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 entity. 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) exceeds the amount we would have been entitled to receive (or required to fund) based solely on our Percentage Interest.   This special earnings allocation to us reduces the amount of income allocated to EPO by an equal amount and may result in EPO being allocated a loss when we are allocated income. It is our expectation that EPO will be allocated a loss by the DEP II Midstream Businesses until such time as growth projects such as the Sherman Extension realize their income and cash flow potential. Our participation in this expected increase in cash flow from growth projects is limited (beyond our fixed annual return amount) to 2% of such upside, with Enterprise GTM receiving 98% of the benefit.

The following table presents our calculation of "Parent interest in income – DEP II Midstream Businesses" for the period from December 8, 2008 to December 31, 2008. We attributed a loss of $4.0 million to EPO (as Parent) for this period following the closing of the DEP II dropdown transaction.

DEP II Midstream Businesses - Base earnings allocation to EPO as Parent (77.4%)		$ 368
Additional income allocation to Duncan Energy Partners:		
Total distributions paid by DEP II Midstream Businesses	$ 5,435	
Duncan Energy Partners' Percentage Interest in total distributions (22.6%)	1,228	
Less distributions paid to Duncan Energy Partners (based on fixed annual return)	5,581	(4,353)
Parent interest in income – DEP II Midstream Businesses (attributed loss)		$ (3,985)

The following table provides a reconciliation of the amounts presented as “Parent interest in Subsidiaries – DEP II Midstream Businesses” on our consolidated balance sheet at December 31, 2008. Amounts are for the period from the closing of the dropdown transaction to December 31, 2008.

Retention by Parent of ownership interest in DEP II Midstream Businesses on December 8, 2008	$ 2,595,507
Allocated loss from DEP II Midstream Businesses to EPO as Parent – December 8 to December 31, 2008	(3,985)
Contributions by EPO in connection with expansion cash calls	21,331
Distributions to Parent of subsidiary operating cash flows	(804)
Other general cash contributions from Parent	955
December 31, 2008 balance	$ 2,613,004

Enterprise III has declined participation in expansion project spending since December 8, 2008. As a result, Enterprise GTM has funded 100% of such growth capital spending, which amount to $21.3 million since the closing date of the DEP II dropdown transaction.

For additional information regarding our agreements with EPO in connection with the DEP II dropdown transaction, see “Relationship with EPO– Company and Limited Partnership Agreements – DEP II Midstream Businesses” under Item 13 of this annual report.

Liquidity and Capital Resources

Our primary cash requirements, in addition to normal operating expenses and debt service, are for working capital, capital expenditures, business combinations and distributions to our partners. We expect to fund our short-term needs for such items as operating expenses and sustaining capital expenditures with operating cash flows and borrowings under our 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 parties. We expect to fund cash distributions to partners primarily with operating cash flows. Our debt service requirements are expected to be funded by operating cash flows and/or financing arrangements.

At December 31, 2008, we had approximately $110.0 million of liquidity, which included $13.0 million of unrestricted cash on hand and approximately $97.0 million of credit available under the DEP I Revolving Credit Facility. At December 31, 2008, our total debt balance was $484.3 million, which includes $202.0 million outstanding under the DEP I Revolving Credit Facility and the $282.3 million we borrowed on December 8, 2008 under the DEP II Term Loan Agreement. We also have a $1.0 million letter of credit outstanding under the DEP I Revolving Credit Facility as of December 31, 2008. Our bank loan agreements require us to maintain certain financial and other customary covenants. We were in compliance with the covenants of our loan agreements at December 31, 2008 and 2007.

It is our belief that we will continue to have adequate liquidity and capital resources to fund future recurring operating and investing activities. For a discussion of our liquidity outlook, see “General Outlook for 2009” within this Item 7.

Registration Statements

We may issue equity or debt securities to assist us in meeting our liquidity and capital spending requirements. On March 6, 2008, we filed a universal shelf registration statement with the SEC to periodically issue up to $1.00 billion in debt and equity securities. We expect to use any proceeds from such offerings for general partnership purposes, including debt repayments, working capital requirements, capital expenditures and business combinations.

On December 8, 2008, in connection with the DEP II dropdown transaction, we issued 41,529 common units to EPO for an aggregate purchase price of $0.5 million, or $12.04 per unit. The price per unit was equal to the closing price per unit on December 5, 2008 as reported by the NYSE. No commissions or discounts were paid in connection with this sale of common units. This sale of common units was registered under our universal shelf registration statement.

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 thousands). For information regarding the individual components of our cash flow amounts, see the Statements of Consolidated Cash Flows.

	For the Year Ended December 31,		
	2008	2007	2006
Net cash flows provided by operating activities	$ 220.2	$ 217.1	$ 195.6
Cash used in investing activities	748.9	352.4	184.5
Cash provided by (used in) financing activities	539.5	137.5	(11.2)

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, crude oil and certain petrochemicals. The products that we process, sell or transport are principally used as fuel for residential, agricultural and commercial heating; as feedstocks in petrochemical manufacturing; and in the production of motor gasoline. Reduced demand for our services or products by industrial customers, whether because of a decline in general economic conditions, reduced demand for the end products made with our products, or increased competition from other service providers or producers due to pricing differences or other reasons, could have a negative impact on our earnings and operating cash flows.

We use the indirect method to compute net cash flows provided by operating activities. See Note 18 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for information regarding this method of presentation.

Cash used in investing activities primarily represents expenditures for additions to property, plant and equipment, business combinations and investments in unconsolidated affiliates. 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 2008 with 2007

Operating activities. Net cash flows provided by operating activities were $220.2 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 $748.9 million for the year ended December 31, 2008 compared to $352.4 million for the year ended December 31, 2007. The increase of $396.5 million is primarily due to growth capital spending for additions to property, plant and equipment of the DEP II Midstream Businesses.

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 the following:

- § Contributions by the former owners of the DEP II Midstream Businesses increased $378.8 million year-to-year primarily due to the funding of growth capital spending of these businesses.

- § Contributions by EPO (as Parent) increased $78.3 million year-to-year primarily due to growth capital spending of the DEP I Midstream Businesses. EPO has agreed to fund 100% of the project costs of certain expansion projects of South Texas NGL and Mont Belvieu Caverns. For additional information regarding these contributions, see "Parent Interest in Subsidiaries - DEP I Midstream Businesses" within this Item 7.

- § Our net borrowings under loan agreements increased $84.3 million year-to-year. Borrowings for 2008 consist primarily of $282.3 received from the execution of the DEP II Term Loan Agreement in connection with the DEP II dropdown transaction.

- § Net proceeds from equity offerings decreased by $290.0 million year-to-year. In February 2007, we completed our IPO, which generated net proceeds of $290.5 million.

- § Distributions to Parent in connection with dropdown transactions decreased $179.1 million year-to-year. We distributed $280.5 million in cash to EPO (as Parent) in December 2008 in connection with the DEP II dropdown transaction. In February 2007, we distributed $459.6 million to EPO in connection with the DEP I dropdown transaction.

Comparison of 2007 with 2006

Operating activities. Net cash flows provided by operating activities were $217.1 million for the year ended December 31, 2007 compared to $195.6 million for the year ended December 31, 2006. The improvement in operating cash flow is generally due to the increase in gross operating margin between periods adjusted for the timing of related cash receipts and disbursements.

Investing activities. Net cash flows used in investing activities were $352.4 million for the year ended December 31, 2007 compared to $184.5 million for the year ended December 31, 2006. The increase of $167.9 million is primarily due to growth capital spending for additions to property, plant and equipment of the DEP II Midstream Businesses.

Financing activities. Net cash flows provided by financing activities for the year ended December 31, 2007 were $137.5 million compared with net cash flows used by financing activities of $11.2 million for the year ended December 31, 2006. The change of $148.7 million is primarily due to the following:

- § We had no debt outstanding prior to our IPO. In February 2007, we borrowed $200.0 million under the DEP I Revolving Credit Facility.

- § Our IPO in February 2007 generated net proceeds of $290.5 million. Distributions to our partners totaled $21.8 million following our IPO.

- § We distributed $459.6 million in cash to EPO (as Parent) as partial consideration for the equity interests we received in the DEP I dropdown transaction.

- § Contributions by the former owners of the DEP I and DEP II Midstream Businesses increased a net $66.5 million year-to-year primarily due to the funding of growth capital spending of these businesses.

- § Contributions by EPO (as Parent) increased $105.0 million year-to-year primarily due to growth capital spending of the DEP I Midstream Businesses.

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 thousands):

	For the Year Ended December 31,		
	2008	2007	2006
Capital spending for property, plant and equipment, net of contributions in aid of construction costs	$ 749,583	$ 330,071	$ 173,636
Capital spending for business combinations	1	35,000	11,675
Capital spending for investments in unconsolidated affiliates	141	(85)	59
Total capital spending	$ 749,725	$ 364,986	$ 185,370

The majority of our capital spending during 2008 and 2007 was attributable to ongoing expansions of the Texas Intrastate System, including the Sherman Extension in North Texas.

Based on information currently available, we estimate our consolidated capital spending for property, plant and equipment for 2009 will approximate $430.0 million, which includes estimated expenditures of $375.0 million for growth capital projects and $55.0 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 dropdown transactions. In order to fund our share of growth capital spending, we depend on our 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 “Parent Interest in Subsidiaries - DEP I Midstream Businesses” within this Item 7 for information regarding EPO’s funding of certain growth capital spending of South Texas NGL and Mont Belvieu Caverns. For information regarding the expansion capital funding arrangements of the DEP II Midstream Businesses, see “Relationship with EPO - Company and Limited Partnership Agreements - DEP II Midstream Businesses” under Item 13 of this annual report.

At December 31, 2008, we had approximately $126.8 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.

Pipeline Integrity Costs

Our NGL, petrochemical and natural gas pipelines are subject to pipeline safety programs administered by the U.S. Department of Transportation, through its Office of Pipeline Safety. 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 and 2006, the DEP II Midstream Businesses recovered $31.1 million and $13.7 million, respectively from El Paso related to the 2006 and 2005 pipeline integrity expenditures. During 2007, the DEP II Midstream Businesses received the final payment of $5.4 million from El Paso related to this indemnity.

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

	For the Year Ended December 31,		
	2008	**2007**	**2006**
Expensed	$ 20,550	$ 14,915	$ 6,796
Capitalized	22,934	24,040	5,396
Total	$ 43,484	$ 38,955	$ 12,192

We expect our cash outlay for the pipeline integrity program, irrespective of whether such costs are capitalized or expensed, to approximate $51.3 million for 2009.

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, 2008 and 2007, the net book value of our property, plant and equipment was $4.33 billion and $3.74 billion, respectively. We recorded $158.5 million, $163.4 million and $148.2 million in depreciation expense for the years ended December 31, 2008, 2007 and 2006, respectively.

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, oil or NGLs. Long-lived assets with recorded values that are not expected to be recovered through expected 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 existing 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 could result in our recording an impairment charge.

We did not recognize any asset impairment charges during the periods presented. In addition, we did not recognize any impairment charges related to our Evangeline equity method investment during the periods presented.

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 the nature of the asset, the business in which it is utilized, and the economic returns it is generating or is expected to generate.

Our customer relationship intangible assets primarily represent the customer base we acquired in connection with the DEP II dropdown. These customer relationships were acquired by Enterprise Products Partners in connection with its merger with a third party partnership in September 2004 and a business combination it completed during 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 based on a number of factors, including reserve estimates, the economic viability of production and exploration activities and other industry factors.

We acquired contract-based intangible assets in connection with the DEP I and DEP II dropdown 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, etc.);

§ 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. Additionally, if we determine that an intangible asset's unamortized cost may not be recoverable due to impairment, we may be required to reduce the carrying value and the subsequent useful life of the asset. Any such write-down of the value and unfavorable change in the useful life of an intangible asset would increase operating costs and expenses at that time.

At December 31, 2008 and 2007, the carrying value of our intangible asset portfolio was $52.3 million and $48.6 million, respectively. We recorded $9.1 million, $7.2 million and $7.5 million in amortization expense associated with our intangible assets for the years ended December 31, 2008, 2007 and 2006, respectively.

For additional information regarding our intangible assets see Notes 2 and 9 of the Notes to Consolidated Financial Statements included under Item 8 of 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 (at the reporting unit level) for impairment during the second quarter 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 contained 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 goodwill to its implied fair value. The carrying value of our goodwill was $4.9 million at both December 31, 2008 and 2007. Our goodwill 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.   We did not record any goodwill impairment charges during the periods presented.

For additional information regarding our goodwill, see Notes 2 and 9 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Our revenue recognition policies and use of estimates for revenues and expenses

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.   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), we record any necessary allowance for doubtful accounts.

We make estimates for certain revenue and expense items due to time constraints on the financial accounting and reporting process. At times, we must estimate revenues from a customer before we actually bill the customer or accrue an expense we incur before physically receiving a vendor's invoice. Such estimates reverse in the following period and are offset by our recording the actual customer billing and vendor invoice amounts. If the basis of our estimates proves to be substantially incorrect, it could result in material adjustments in results of operations between periods. For all periods presented, our revenue and cost estimates are substantially correct as compared to actual amounts.

Reserves for environmental matters

Each of our business segments is subject to 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, 2008, none of our estimated environmental remediation liabilities are discounted to present value since the ultimate amount and timing of cash payments for such liabilities are not readily determinable.

At December 31, 2008 and 2007, we had a liability for environmental remediation of $0.6 million and $17.8 million, respectively, which was derived from a range of reasonable estimates based upon studies and site surveys. We follow the provisions of American Institute of Certified Public Accountants Statement of Position 96-1, which provides key guidance on recognition, measurement and disclosure of remediation liabilities. We have recorded our best estimate of the cost of remediation activities.

See Item 3 of this annual report for recent developments regarding environmental matters.

Natural gas imbalances

In the pipeline transportation business, natural gas 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 on-going 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 which 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 is representative of the estimated value of the imbalances upon final settlement. Changes in natural gas prices may impact our estimates.

At December 31, 2008 and 2007, our imbalance receivables were $35.7 million and $34.2 million, respectively. At December 31, 2008 and 2007, our imbalance payables were $43.6 million and $37.3 million, respectively, and are reflected as a component of “Accrued products payables” on our Consolidated Balance Sheets.

Other Items

Contractual Obligations

The following table summarizes our significant contractual obligations at December 31, 2008 (dollars in thousands). For additional information regarding these obligations, see Note 16 of the Notes to Consolidated Financial Statements included under Item 8 of 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)	$ 482,250	$ --	$ 482,250	$ --	$ --
Estimated cash interest payments (3)	$ 49,127	$ 20,152	$ 28,975	$ --	$ --
Operating lease obligations (4)	$ 126,441	$ 10,676	$ 18,319	$ 15,992	$ 81,454
Purchase obligations:					
Product purchase commitments:					
Estimated payment obligations:					
Natural gas (5)	$ 508,488	$ 127,035	$ 254,070	$ 127,383	$ --
Other	$ 245	$ 119	$ 84	$ 42	$ --
Underlying major volume commitments:					
Natural gas (in BBtus)	73,050	18,250	36,500	18,300	--
Capital expenditure commitments (6)	$ 126,805	$ 126,805	$ --	$ --	$ --
Other long-term liabilities (7)	$ 7,222	$ --	$ 4,214	$ 68	$ 2,940
Total	$ 1,300,578	$ 284,787	$ 787,912	$ 143,485	$ 84,394

(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 obligations for the periods indicated. See Note 10 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, 2008. With respect to variable-rate debt, we applied the weighted-average interest rates paid during 2008. See Note 10 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for information regarding variable interest rates charged in 2008 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, 2008. See Note 6 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for information regarding our financial 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 16 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 16 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for information regarding our purchase obligations.

(6) Capital expenditure commitments are reflected on a 100% basis. We expect reimbursements of $117.6 million from EPO.

(7) As presented on our Consolidated Balance Sheet at December 31, 2008, other long-term liabilities consist primarily of (i) liabilities recorded in connection with our interest rate risk hedging portfolio that we expect to settle in 2010 and (ii) liabilities for asset retirement obligations that we expect to settle beyond 2012. For information regarding our financial instruments and asset retirement obligations, see Notes 6 and 7, respectively, of our Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Off-Balance Sheet Arrangements

At December 31, 2008, Evangeline’s debt obligations consisted of (i) $8.2 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. See Note 10 of the Notes to Consolidated Financial Statements for additional information regarding this debt obligation.

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 condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources.

Summary of Related Party Transactions

The following table summarizes our related party revenue and expense transactions for the periods indicated (dollars in thousands):

	For the Year Ended December 31,		
	2008	2007	2006
Revenues:			
Revenues from EPO	$ 376,474	$ 196,313	$ 226,241
Sales of natural gas – Evangeline	362,890	264,248	277,741
Natural gas transportation services – Energy Transfer Equity	903	437	--
NGL and petrochemical storage services – TEPPCO	1,381	40	26
Total related party revenues	$ 741,648	$ 461,038	$ 504,008
Operating costs and expenses:			
EPCO administrative services agreement	$ 72,048	$ 63,710	$ 65,474
Expenses with EPO	255,382	32,014	12,354
Purchases of natural gas – Nautilus	10,250	3,531	1,573
Expenses with Energy Transfer Equity:	7,638	4,970	--
Expenses with TEPPCO	(194)	(74)	(154)
Other related party expenses, primarily with Evangeline	14	110	2
Total related party operating costs and expenses	$ 345,138	$ 104,261	$ 79,249
General and administrative costs:			
EPCO administrative services agreement	$ 15,663	$ 11,482	$ 10,157
Other related party general and administrative costs	(781)	(67)	--
Total related party general and administrative costs	$ 14,882	$ 11,415	$ 10,157

One of our principal advantages is our relationship with EPO and EPCO. EPO is a wholly owned subsidiary of Enterprise Products Partners through which Enterprise Products Partners conducts its business. Enterprise Products Partners is controlled by its general partner, Enterprise Products GP, LLC ("EPGP"), which in turn is a wholly owned subsidiary of Enterprise GP Holdings. The general partner of Enterprise GP Holdings is EPE Holdings, LLC ("EPE Holdings"), which is a wholly owned subsidiary of a private company controlled by Dan L. Duncan (see Item 10). Mr. Duncan is Chairman of our general partner and is a Group Co-Chairman and the controlling shareholder of EPCO. Our general partner is wholly owned by EPO and EPCO provides all of our employees, including our executive officers.

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 growth objectives of EPO and other affiliates under common control.

At December 31, 2008, EPO owned approximately 74% of our limited partner interests and 100% of our general partner. EPO was sponsor of the DEP I and DEP II dropdown 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 dropdown transactions (including consideration provided to EPO), see the related sections under "Overview of Business" within this Item 7. For a description of EPO's Parent interest in the income and net assets of the DEP I and DEP II Midstream Businesses, see "Parent Interest in Subsidiaries" within this Item 7. 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.

A significant portion of our related party revenues from EPO are attributable to the sale of natural gas and NGLs and the provision of storage services. Our related party expenses with EPO primarily involve the purchase of natural gas by Acadian Gas. Acadian Gas sells natural gas to Evangeline (an unconsolidated affiliate) that, in turn, enables Evangeline to meet its commitment under a sales contract with a third party utility customer. Evangeline is our largest customer and accounted for 22.7%, 21.7% and 22.0% of our consolidated revenues in 2008, 2007 and 2006, respectively.

We have no employees. All of our operating functions and general and administrative support services are provided by employees of EPCO pursuant to an administrative services agreement (the "ASA"). We, Enterprise Products Partners, Enterprise GP Holdings, TEPPCO Partners, L.P. ("TEPPCO") and our respective general partners are parties to the ASA.

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.

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.

For additional information regarding our relationships with related parties, see Item 13 of this annual report.

Non-GAAP Reconciliations

A reconciliation of our measurement of total non-GAAP gross operating margin to GAAP operating income and further to GAAP net income is presented in the following table (dollars in thousands):

	For the Year Ended December 31,		
	2008	**2007**	**2006**
Total non-GAAP segment gross operating margin	$ 253,006	$ 224,760	$ 219,086
Adjustments to reconcile total non-GAAP segment			
gross operating to GAAP net income:			
Depreciation, amortization and accretion in			
operating costs and expenses	(167,380)	(175,308)	(155,998)
Gain (loss) on asset sales and related transactions in			
operating costs and expenses	532	80	26
General and administrative costs	(18,305)	(13,116)	(10,227)
GAAP operating income	67,853	36,416	52,887
Other income (expense), net	(11,443)	(8,645)	459
Provision for income taxes	(1,095)	(4,172)	(1,682)
Parent interest in loss (income) of subsidiaries	(7,369)	(19,973)	--
Cumulative effect of accounting changes	--	--	18
GAAP net income	$ 47,946	$ 3,626	$ 51,682

Recent Accounting Developments

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

§ SFAS 141(R), Business Combinations;

§ FASB Staff Position ("FSP") SFAS 142-3, Determination of the Useful Life of Intangible Assets;

§ SFAS 157, Fair Value Measurements;

§ SFAS 160, Noncontrolling Interests in Consolidated Financial Statements – An amendment of ARB 51;

§ SFAS 161, Disclosures about Derivative Instruments and Hedging Activities – An Amendment of SFAS 133; and

§ Emerging Issues Task Force ("EITF") 08-6, Equity Method Investment Accounting Considerations.

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

We are exposed to financial market risks, including changes in commodity prices and interest rates. We may use financial instruments (i.e. futures, forwards, swaps, options and other financial instruments with similar characteristics) to mitigate the risks of certain identifiable and anticipated transactions.

Interest Rate Risk Hedging Program

As presented in the following table, we had three interest rate swap agreements outstanding at December 31, 2008 that were accounted for as cash flow hedges.

Hedged Variable Rate Debt	Number of Swaps	Period Covered by Swap	Termination Date of Swap	Variable to Fixed Rate (1)	Notional Value
Duncan Energy Partners' Revolver, due Feb. 2011	3	Sep. 2007 to Sep. 2010	Sep. 2010	1.47% to 4.62%	$175.0 million

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

In September 2007, we executed three floating-to-fixed interest rate swaps having a combined notional value of $175 million. The purpose of entering into these transactions was to reduce the sensitivity of our earnings to changes in variable interest rates charged under the DEP I Revolving Credit Facility. We recognized a loss in interest expense of $2.0 million and a benefit of $0.2 million from these swaps during the years ended December 31, 2008 and 2007, respectively, which includes a nominal amount of ineffectiveness. In 2009, we expect to reclassify $6.0 million of accumulated other comprehensive loss that was generated by these interest rate swaps as an increase to interest expense.

The aggregate fair value of these interest rate swaps was a liability of $9.8 million and a liability of $3.8 million for the years ended December 31, 2008 and 2007, respectively. As cash flow hedges, any increase or decrease in fair value (to the extent such financial instruments are effective hedges) would be recorded in other comprehensive income and amortized into income over the settlement period hedged. Any hedge ineffectiveness is recorded directly into earnings as an increase in interest expense. The following table shows the effect of hypothetical price movements on the estimated fair value ("FV") of our interest rate swap portfolio (dollars in thousands).

		Portfolio FV at	
Scenario	Resulting Classification	December 31, 2008	February 3, 2009
FV assuming no change in underlying interest rates	*Liability*	$ 9,799	$ 9,373
FV assuming 10% increase in underlying interest rates	*Liability*	9,445	8,975
FV assuming 10% decrease in underlying interest rates	*Liability*	10,153	9,772

Commodity Risk Hedging Program

In addition to its natural gas transportation business, Acadian Gas engages in the purchase and sale of natural gas to third party customers in the Louisiana area. The price of natural gas fluctuates in response to changes in supply, market uncertainty, and a variety of additional factors that are beyond our control. We may use commodity-based financial instruments such as futures, swaps and forward contracts to mitigate such risks. In general, the types of risks we attempt to hedge are those related to the variability of future earnings and cash flows resulting from changes in commodity prices. The derivatives we utilize may be settled in cash or with another financial instrument.

Acadian Gas also enters into a small number of cash flow hedges in connection with its purchase of natural gas held-for-sale to third parties. In addition, Acadian Gas enters into a limited number of offsetting mark-to-market financial instruments that effectively fix the price of natural gas for certain of its customers.

Historically, the use of commodity financial instruments by Acadian Gas was governed by policies established by the general partner of Enterprise Products Partners. Our general partner now monitors the hedging strategies associated with the physical and financial risks of Acadian Gas, 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.

The fair value of the Acadian Gas commodity financial instrument portfolio was a negligible amount at both December 31, 2008 and 2007. We recorded losses of $1.1 million and $0.8 million for the years ended December 31, 2007 and 2006, respectively, and a nominal loss for the year ended December 31, 2008.

We assess the risk of our commodity financial instrument portfolio using a sensitivity analysis model. The sensitivity analysis applied to this portfolio measures the potential income or loss (i.e., the change in fair value of the portfolio) based upon a hypothetical 10% movement in the underlying quoted market prices of the commodity financial instruments outstanding at the dates indicated within the following table. The following table presents the effect of hypothetical price movements on the estimated fair value of this portfolio at the dates presented (dollars in thousands):

		Portfolio FV at		
Scenario	**Resulting Classification**	**December 31, 2007**	**December 31, 2008**	**February 3, 2009**
FV assuming no change in underlying commodity prices	*Asset (Liability)*	$ 33	$ (84)	$ (4)
FV assuming 10% increase in underlying commodity prices	*Asset (Liability)*	(409)	(92)	(3)
FV assuming 10% decrease in underlying commodity prices	*Asset (Liability)*	475	(80)	(4)

Product purchase commitments

We have long and short-term purchase commitments with several suppliers. The purchase prices that we are obligated to pay under these contracts are based on market prices at the time we take delivery of the volumes. For additional information regarding these commitments, see “Other Items – Contractual Obligations” included under Item 7 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 Report.

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

None.

Item 9A. ***Controls and Procedures.***

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

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

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

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting during the fourth quarter of 2008 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

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

MANAGEMENT'S ANNUAL REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING AS OF DECEMBER 31, 2008

The management of Duncan Energy Partners L.P. and its consolidated subsidiaries, including its chief executive officer and chief financial officer, is responsible for establishing and maintaining adequate internal control over financial reporting, as defined in Rules 13a-15(f) and 15d-15(f) of the Securities Exchange Act of 1934, as amended. Our internal control system was designed to provide reasonable assurance to Duncan Energy Partners' management and Board of Directors regarding the preparation and fair presentation of published financial statements. However, our management does not represent that our disclosure controls and procedures or internal controls over financial reporting will prevent all error and all fraud. A control system, no matter how well conceived and operated, can provide only a reasonable, not an absolute, assurance that the objectives of the control system are met.

Our management assessed the effectiveness of Duncan Energy Partners' internal control over financial reporting as of December 31, 2008. In making this assessment, it used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") in *Internal Control—Integrated Framework*. This assessment included a review of the design and operating effectiveness of internal controls over financial reporting as well as the safeguarding of assets. Based on our assessment, we believe that, as of December 31, 2008, Duncan Energy Partners' internal control over financial reporting is effective based on those criteria.

Our Audit, Conflicts and Governance Committee is composed of directors who are not officers or employees of our general partner. It meets regularly with members of management, the internal auditors and the representatives of the independent registered public accounting firm to discuss the adequacy of Duncan Energy Partners' internal controls over financial reporting, financial statements and the nature, extent and results of the audit effort. Management reviews with the Audit, Conflicts and Governance Committee all of Duncan Energy Partners' significant accounting policies and assumptions affecting the results of operations. Both the independent registered public accounting firm and internal auditors have direct access to the Audit, Conflicts and Governance Committee without the presence of management.

Our independent registered public accounting firm has issued an attestation report on our internal control over financial reporting. That report is included within this Item 9A.

Pursuant to the requirements of Rules 13a-15(f) and 15d-15(f) of the Securities Exchange Act of 1934, as amended, this Annual Report on Internal Control Over Financial Reporting has been signed below by the following persons on behalf of the registrant and in the capacities indicated below on March 2, 2009.

/s/ *Richard H. Bachmann*			/s/ *W. Randall Fowler*	
Name:	Richard H. Bachmann		Name:	W. Randall Fowler
Title:	Chief Executive Officer of our general partner, DEP Holdings, LLC		Title:	Chief Financial Officer of our general partner, DEP Holdings, LLC

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 internal control over financial reporting of Duncan Energy Partners L.P. and subsidiaries (the "Company") as of December 31, 2008, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Annual Report on Internal Control over Financial Reporting as of December 31, 2008. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

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

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

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

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, based on the criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet and the related consolidated statements of operations and comprehensive income, cash flows, and partners' equity as of and for the year ended December 31, 2008 of the Company and our report dated March 2, 2009 (which report expresses an unqualified opinion and includes an explanatory paragraph relating to the preparation of the financial statements of Duncan Energy Partners L.P. from the separate records maintained by Enterprise Products Partners L.P.) on those financial statements.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
March 2, 2009

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

None.

PART III

Item 10. ***Directors, Executive Officers and Corporate Governance.***

Partnership Management

As is commonly the case with publicly traded limited partnerships, we do not directly employ any of the persons responsible for the management or operations of our business. These functions are performed by the employees of EPCO pursuant to the ASA under the direction of the Board of Directors (the “Board”) and executive officers of our general partner. For a description of the ASA, see “Certain Relationships and Related Transactions – Relationship with EPCO” under Item 13 of this annual report.

The executive officers of DEP GP, our general partner, are elected for one-year terms and may be removed, with or without cause, only by the Board. Our unitholders do not elect the officers or directors of DEP GP. Although the members of our Board are elected by EPO, Dan L. Duncan, through his indirect control of EPO and our general partner, has the ability to elect, remove and replace at any time, all of the officers and directors of DEP GP. Each member of the Board of our general partner serves until such member’s death, resignation or removal. The employees of EPCO who served as directors of DEP GP were Messrs. Duncan, Bachmann, Creel, Cunningham, Fowler and Teague. Mr. Teague was appointed a Director of DEP GP in July 2008.

Because we are a limited partnership and meet the definition of a “controlled company” under the listing standards of the NYSE, we are not required to comply with certain requirements of the NYSE. Accordingly, we have elected to not comply with Section 303A.01 of the NYSE Listed Company Manual, which would require that the Board be comprised of a majority of independent directors. In addition, we have elected to not comply with Sections 303A.04 and 303A.05 of the NYSE Listed Company Manual, which would require that the Board maintain a Nominating Committee and a Compensation Committee, each consisting entirely of independent directors.

Notwithstanding any contractual limitation on its obligations or duties, DEP GP is liable for all debts we incur (to the extent not paid by us), except to the extent that such indebtedness or other obligations are non-recourse to DEP GP. Whenever possible, DEP GP intends to make any such indebtedness or other obligations non-recourse to itself.

Under our limited partnership agreement and subject to specified limitations, we will indemnify to the fullest extent permitted by Delaware law, from and against all losses, claims, damages or similar events, any director or officer, or while serving as director or officer, any person who is or was serving as a tax matters member or as a director, officer, tax matters member, employee, partner, manager, fiduciary or trustee of our partnership or any of our affiliates. Additionally, we will indemnify to the fullest extent permitted by law, from and against all losses, claims, damages or similar events, any person who is or was an employee (other than an officer) or agent of our partnership.

Corporate Governance

We are committed to sound principles of governance. Such principles are critical for us to achieve our performance goals, and maintain the trust and confidence of investors, employees, suppliers, business partners and stakeholders.

A key element for strong governance is independent members of the Board. Pursuant to the NYSE listing standards, a director will be considered independent if the Board determines that he or she does not have a material relationship with us or our general partner (either directly or as a partner, unitholder or officer of an organization that has a material relationship with us or our general partner). Based on the foregoing, the Board has affirmatively determined that William A. Bruckmann, III, Larry J. Casey and Joe D. Havens are "independent" directors under the NYSE rules. In making its determination, the Board's considerations included the fact that Mr. Havens sold 75,865 units of Enterprise GP Holdings L.P. at $19.68 per unit and 100,000 common units of Enterprise Products Partners L.P. at $22.15 per unit to affiliates of Mr. Duncan on February 9, 2009.

Code of Conduct and Ethics and Corporate Governance Guidelines

DEP GP has adopted a "*Code of Conduct*" that applies to all directors, officers and employees. This code sets out our requirements for compliance with legal and ethical standards in the conduct of our business, including general business principles, legal and ethical obligations, compliance policies for specific subjects, obtaining guidance, the reporting of compliance issues and discipline for violations of the code. Our Code of Conduct also establishes policies applicable to our chief executive officer, chief financial officer, principal accounting officer and senior financial and other managers to prevent wrongdoing and to promote honest and ethical conduct, including ethical handling of actual and apparent conflicts of interest, compliance with applicable laws, rules and regulations, full, fair, accurate, timely and understandable disclosure in public communications and prompt internal reporting violations of the code.

Governance guidelines, together with committee charters, provide the framework for effective governance. The Board has adopted the *Governance Guidelines of Duncan Energy Partners*, which address several matters, including qualifications for directors, responsibilities of directors, retirement of directors, the composition and responsibility of ACG Committee, the conduct and frequency of board and committee meetings, management succession, director access to management and outside advisors, director compensation, director orientation and continuing education, and annual self-evaluation of the board. The Board recognizes that effective governance is an on-going process, and thus, the Board will review the Governance Guidelines of Duncan Energy Partners annually or more often as deemed necessary.

We provide access through our website at www.deplp.com to current information relating to governance, including the Code of Conduct, the Governance Guidelines of Duncan Energy Partners and other matters impacting our governance principles. You may also contact our investor relations department at (866) 230-0745 for printed copies of these documents free of charge.

ACG Committee

The sole committee of the Board is its ACG Committee. In accordance with NYSE rules and Section 3(a)(58)(A) of the Securities Exchange Act of 1934, the Board has named three of its members to serve on its ACG Committee. The members of the ACG Committee are independent directors, free from any relationship with us or any of our subsidiaries that would interfere with the exercise of independent judgment.

The members of the ACG Committee must have a basic understanding of finance and accounting and be able to read and understand fundamental financial statements, and at least one member of the ACG Committee shall have accounting or related financial management expertise. The members of the ACG

Committee are Messrs. Bruckmann, Casey and Havens. The Board has affirmatively determined that Mr. Bruckmann satisfies the definition of “audit committee financial expert” as defined in Item 401(h) of Regulation S-K promulgated by the SEC.

The duty of the ACG Committee is to address audit and conflicts-related items and general corporate governance matters. From an audit and conflicts standpoint, the primary responsibilities of the ACG Committee include:

§ monitoring the integrity of our financial reporting process and related systems of internal control;

§ ensuring our legal and regulatory compliance and that of DEP GP;

§ overseeing the independence and performance of our independent public accountant;

§ approving all services performed by our independent public accountant;

§ providing for an avenue of communication among the independent public accountant, management, internal audit function and the Board;

§ encouraging adherence to and continuous improvement of our policies, procedures and practices at all levels;

§ reviewing areas of potential significant financial risk to our businesses; and

§ approving awards granted under our long-term incentive plans.

If the Board believes that a particular matter presents a conflict of interest and proposes a resolution, the ACG Committee has the authority to review such matter to determine if the proposed resolution is fair and reasonable to us. Any matters approved by the ACG Committee are conclusively deemed to be fair and reasonable to our business, approved by all of our partners and not a breach by DEP GP or the Board of any duties they may owe us or our unitholders.

Pursuant to its formal written charter, the ACG Committee has the authority to conduct any investigation appropriate to fulfilling its responsibilities, and it has direct access to our independent public accountants as well as any EPCO personnel whom it deems necessary in fulfilling its responsibilities. The ACG Committee has the ability to retain, at our expense, special legal, accounting or other consultants or experts it deems necessary in the performance of its duties.

From a governance standpoint, the ACG Committee’s primary duties and responsibilities are to develop and recommend to the Board a set of governance principles applicable to us, and to review such guidelines from time to time, making any changes that the ACG Committee deems necessary. The ACG Committee assists the Board in fulfilling its oversight responsibilities.

A copy of the ACG Committee charter is available on our website, www.deplp.com. You may also contact our investor relations department at (866) 230-0745 for a printed copy of this document free of charge.

NYSE Corporate Governance Listing Standards

On March 4, 2008, Richard H. Bachmann, our Chief Executive Officer, certified to the NYSE (as required by Section 303A.12(a) of the NYSE Listed Company Manual) that he was not aware of any violation by us of the NYSE’s Corporate Governance listing standards as of March 4, 2008.

Executive Sessions of Non-Management Directors

The Board holds regular executive sessions in which non-management directors meet without any members of management present. The purpose of these executive sessions is to promote open and candid discussion among the non-management directors. During such executive sessions, one director is designated as the "presiding director," who is responsible for leading and facilitating such executive sessions. Currently, the presiding director is Mr. Bruckmann.

In accordance with NYSE rules, we have established a toll-free, confidential telephone hotline (the "Hotline") so that interested parties may communicate with the presiding director or with all the non-management directors as a group. All calls to this Hotline are reported to the chairman of the ACG Committee, who is responsible for communicating any necessary information to the other non-management directors. The number of our confidential Hotline is (877) 888-0002.

Directors and Executive Officers of DEP GP

The following table sets forth the name, age and position of each of the directors and executive officers of our general partner at March 2, 2009.

Name	Age	Position with DEP GP
Dan L. Duncan (1)	76	Director and Chairman
Richard H. Bachmann (1)	56	Director, President and Chief Executive Officer
W. Randall Fowler (1)	52	Director, Executive Vice President and Chief Financial Officer
A. James Teague (1)	63	Director, Executive Vice President and Chief Commercial Officer
Michael A. Creel	55	Director
Dr. Ralph S. Cunningham	68	Director
Larry J. Casey (2)	76	Director
Joe D. Havens (2)	79	Director
William A. Bruckmann, III (2,3)	57	Director
William Ordemann (1)	49	Executive Vice President
Michael J. Knesek (1)	54	Senior Vice President, Principal Accounting Officer and Controller

(1) Executive Officer
(2) Member of ACG Committee
(3) Chairman of ACG Committee

Dan L. Duncan. Mr. Duncan was elected Chairman and a Director of DEP GP in October 2006, Chairman and a Director of EPE Holdings in August 2005 and Chairman and a Director of EPGP in April 1998. Mr. Duncan served as the sole Chairman of EPCO from 1979 to December 2007. Mr. Duncan now serves as Group Co-Chairman of EPCO with his daughter, Ms. Randa Duncan Williams. He also serves as a Honorary Trustee of the Board of Trustees of the Texas Heart Institute at Saint Luke's Episcopal Hospital.

Richard H. Bachmann. Mr. Bachmann was elected President, Chief Executive Officer and a Director of DEP GP in October 2006 and a Director of EPE Holdings and EPGP in February 2006. Mr. Bachmann previously served as a Director of EPGP from June 2000 to January 2004. Mr. Bachmann was elected Executive Vice President, Chief Legal Officer and Secretary of EPGP and of EPCO, and a Director of EPCO, in January 1999. In December 2007, Mr. Bachmann was also elected as a Co-Group Vice Chairman of EPCO. In November 2006, Mr. Bachmann was appointed as an independent manager of Constellation Energy Partners LLC. Mr. Bachmann also serves as a member of the Audit, Conflicts, Compensation and Nominating and Governance committees of Constellation Energy Partners LLC.

W. Randall Fowler. Mr. Fowler was elected Executive Vice President and Chief Financial Officer of DEP GP and EPGP in August 2007. Mr. Fowler has served as a Director of DEP GP since October 2006 and EPE Holdings and EPGP since February 2006. Prior to his promotion to Executive Vice President and Chief Financial Officer of DEP GP in August 2007, Mr. Fowler served as a Senior Vice President and treasurer of DEP GP since October 2006. Mr. Fowler served as Senior Vice President and Treasurer of EPGP from February 2005 to August 2007. Mr. Fowler was elected President and Chief

Executive Officer of EPCO in December 2007. Mr. Fowler, a certified public accountant (inactive), joined Enterprise Products Partners as Director of Investor Relations in January 1999 and held senior management positions within the EPCO group of companies from August 2000 to February 2005.

A. James Teague. Mr. Teague was elected a Director of DEP GP and Chief Commercial Officer in July 2008. Mr. Teague joined the EPCO family of companies in connection with Enterprise Products Partners' acquisition of certain midstream energy assets from affiliates of Shell Oil Company in 1999. Mr. Teague was elected an Executive Vice President of EPGP in November 1999. From 1998 to 1999, Mr. Teague served as President of Tejas Natural Gas Liquids, LLC, then an affiliate of Shell. From 1997 to 1998, he was President of Marketing and Trading for Mapco Inc.

Michael A. Creel. Mr. Creel was elected a Director of DEP GP in October 2006. From October 2006 to August 2007, Mr. Creel served as the Chief Financial Officer and an Executive Vice President of DEP GP. In August 2007, Mr. Creel resigned these positions with DEP GP and was appointed President and Chief Executive Officer of EPGP.

Mr. Creel, a certified public accountant, has held various senior and executive management positions within the EPCO group of companies since November 1999. Apart from his current position as President and Chief Executive Officer of EPGP and a Director of DEP GP, Mr. Creel also serves as Chief Financial Officer of EPCO (since December 2007) and a Director of EPGP (since February 2006). Mr. Creel served as President, Chief Executive Officer and a Director of EPE Holdings from August 2005 through August 2007. Mr. Creel was elected a Director of Edge Petroleum Corporation, a publicly traded oil and natural gas exploration and production company, in October 2005.

Dr. Ralph S. Cunningham. Dr. Cunningham was elected a Director of DEP GP in August 2007. In addition to these duties, Dr. Cunningham has served as the President and Chief Executive Officer and a Director of EPE Holdings since August 2007 and a Director of EPGP since February 2006. He served as group Executive Vice President and Chief Operating Officer of EPGP from December 2005 to August 2007. Dr. Cunningham also served as a Director of EPGP from 1998 to March 2005 and as Chairman and a Director of TEPPCO GP from March 2005 to November 2005. Dr. Cunningham retired in 1997 from CITGO Petroleum Corporation, where he had served as President and Chief Executive Officer since 1995.

Dr. Cunningham serves as a Director of Tetra Technologies, Inc. (a publicly traded energy services and chemical company), EnCana Corporation (a Canadian publicly traded independent oil and natural gas company) and Agrium, Inc. (a Canadian publicly traded agricultural chemicals company). He was a Director of EPCO from 1987 to 1997.

Larry J. Casey. Mr. Casey was elected a Director of DEP GP in October 2006. Mr. Casey has been a private investor managing real estate and personal investments since he retired in 1982 from a career in the energy industry. In 1974, Mr. Casey founded Xcel Products Company, a NGL and petrochemical trading company. Also in 1974, he founded Xral Underground Storage, the first privately-owned underground merchant storage facility for NGLs and specialty chemicals at Mont Belvieu, Texas. Mr. Casey sold these companies in 1982. Mr. Casey serves on our ACG Committee.

Joe D. Havens. Mr. Havens was elected a Director of DEP GP in October 2006. Mr. Havens has been an entrepreneur engaged in the energy, banking and real estate industries. Mr. Havens founded Enterprise Petroleum Company, Inc., the predecessor to EPCO, in 1968, and sold his interest in the successor entity and related businesses to Mr. Duncan in 1990. Mr. Havens has also served on the board of Directors of the First Commerce Bank of Corpus Christi, a private bank, since 1991, and currently serves as that board's Chairman. Mr. Havens serves on our ACG Committee.

William A. Bruckmann, III. Mr. Bruckmann was elected a Director of DEP GP in October 2006. Mr. Bruckmann has been self-employed as a consultant and private investor since April 2004. From September 2002 to April 2004, Mr. Bruckmann served as a financial advisor with UBS Securities, Inc. He is a former managing Director at Chase Securities, Inc. and has more than 25 years of banking experience, starting with Manufacturers Hanover Trust Company, where he became a senior officer in 1985.

Mr. Bruckmann later served as managing Director, sector head of Manufacturers Hanover's gas pipeline and midstream energy practices through the acquisition of Manufacturers Hanover by Chemical Bank and the acquisition of Chemical Bank by Chase Bank. Mr. Bruckmann also served as a Director of Williams Energy Partners L.P. from May 2001 to June 2003. Mr. Bruckmann serves on our ACG Committee as its Chairman.

William Ordemann. Mr. Ordemann was elected an Executive Vice President of DEP GP in August 2007. He was elected Chief Operating Officer and Executive Vice President of EPGP in August 2007. He served as a Senior Vice President of EPGP from September 2001 to August 2007 and one of its Vice Presidents from October 1999 to September 2001. Prior to joining Enterprise Products Partners, Mr. Ordemann held senior management positions at Shell Midstream Enterprises, LLC and Tejas Natural Gas Liquids, LLC, both of which were affiliates of Shell Oil Company.

Michael J. Knesek. Mr. Knesek, a certified public accountant, was elected Senior Vice President, Principal Accounting Officer and Controller of DEP GP in October 2006. Mr. Knesek has been the Principal Accounting Officer and Controller of EPGP since August 2000 and of EPE Holdings since August 2005. He also serves as a Senior Vice President of EPGP (since February 2005) and EPE Holdings (since August 2005). He previously served as Vice President of EPGP from August 2000 to February 2005. Mr. Knesek has been the Controller and a Vice President of EPCO since 1990.

Section 16(a) Beneficial Ownership Reporting Compliance

Under the federal securities laws, DEP GP, directors of DEP GP, executives (and certain other) officers, and any persons holding more than 10% of our common units are required to report their ownership of common units and any changes in that ownership to us and the SEC. Specific due dates for these reports have been established by regulation, and we are required to disclose in this report any failure to file by these dates during 2008. All such reporting was done in a timely manner in 2008, except that on February 26, 2009, Mr. Havens filed a late Form 4 reporting two purchase transactions that he inadvertently failed to timely report during 2008.

Item 11. *Executive Compensation*.

Executive Officer Compensation

We do not directly employ any of the persons responsible for managing our partnership. Instead, we are managed by our general partner, the executive officers of which are employees of EPCO. Our reimbursement of EPCO's compensation costs is governed by the ASA (see Item 13 of this annual report).

Summary Compensation Table

The following table presents consolidated compensation amounts paid, accrued or otherwise expensed by us with respect to the year ended December 31, 2008 and 2007 for the chief executive officer ("CEO"), chief financial officer ("CFO") and three other most highly compensated executive officers of our general partner. Collectively, these five individuals were our "Named Executive Officers" for 2008.

Compensation paid by us with respect to such Named Executive Officers reflects only that portion of cash compensation paid by EPCO that is allocated to us pursuant to the ASA. We also receive an allocation of a portion of the cost of EPCO's equity-based long-term incentive plans. EPCO accounts for its equity awards in accordance with SFAS 123(R), Share Based Payment.

Our Named Executive Officers did not specifically allocate any of their time to the DEP I or DEP II Midstream Businesses prior to these businesses being contributed to Duncan Energy Partners in connection with the respective dropdown transactions. Our Named Executive Officers allocated their time to Enterprise Products Partners (as a whole) and/or other affiliates of EPCO. As a result, we cannot indicate the historical salaries or other elements of compensation that would have been allocated to us pursuant to the ASA had these businesses been owned by us for all periods presented. Each of the Named Executive Officers continues to perform services for Enterprise Products Partners and/or other affiliates of EPCO. Our Named Executive Officers devote less than a majority of their time on our matters and allocate less than a majority of their compensation to us.

A.J. Teague was elected our Chief Commercial Officer in July 2008. Mr. Teague devoted a minimal amount of his time to our business activities and instead indirectly supervised the activities of other personnel who were more directly involved in our affairs. As a result, Mr. Teague allocated a nominal amount of his compensation to us in 2008. We expect that Mr. Teague will devote more time to our affairs in the future, resulting in a corresponding increase in his compensation expense allocated to us.

Name and Principal Position	Year	Salary ($)	Bonus ($) (1)	Unit Awards ($) (2)	Option Awards ($) (3)	All Other Compensation ($) (4)	Total ($)
Richard H. Bachmann (CEO)	2008	$ 159,688	$ 106,250	$ 329,690	$ 25,696	$ 59,055	$ 680,379
	2007	71,508	43,338	58,485	--	22,077	195,408
W. Randall Fowler (CFO)	2008	63,594	43,750	128,955	10,463	20,882	267,644
	2007	22,675	13,800	14,927	--	5,684	57,086
Gil H. Radtke (5)	2008	81,000	--	138,625	15,188	27,989	262,802
	2007	67,415	25,932	--	--	13,235	106,582
Michael J. Knesek	2008	61,800	26,000	95,348	10,809	21,200	215,157
	2007	22,089	9,000	15,261	--	5,814	52,164
William Ordemann (6)	2008	15,656	10,600	30,072	2,864	6,314	65,506

(1) Amounts represent discretionary annual cash awards accrued with respect to the years presented. Cash awards are paid in February of the following year (e.g., the cash awards for 2008 were paid in February 2009).

(2) Amounts represent expense recognized in accordance with SFAS 123(R) with respect to restricted unit awards issued under the EPCO 1998 Plan and Employee Partnership profits interests awards.

(3) Amounts represent expense recognized in accordance with SFAS 123(R) with respect to unit options issued under the EPCO 1998 Plan and EPD 2008 LTIP.

(4) Amounts primarily represent (i) matching contributions under funded, qualified, defined contribution retirement plans, (ii) quarterly distributions paid on incentive plan awards and (iii) the imputed value of life insurance premiums paid on behalf of the officer.

(5) Mr. Radtke served as our Chief Operating Officer until June 30, 2008, at which time he assumed a role devoted entirely to Enterprise Products Partners' natural gas processing business. Mr. Radtke resigned from the Company in January 2009.

(6) Mr. Ordemann devoted a minimal amount of his time to our business activities during 2007 and instead indirectly supervised the activities of other personnel who were more directly involved in our affairs. As a result, Mr. Ordemann allocated $2 thousand of his compensation to us in 2007.

Compensation Discussion and Analysis

With respect to our Named Executive Officers, compensation paid or awarded by us for the last two fiscal years reflects only that portion of compensation paid by EPCO allocated to us pursuant to the ASA, including an allocation of a portion of the cost of equity-based long-term incentive plans of EPCO. Dan L. Duncan controls EPCO and has ultimate decision-making authority with respect to the compensation of our Named Executive Officers. The following elements of compensation, and EPCO's decisions with respect to determination of payments, are not subject to approvals by our Board or the ACG Committee of our general partner. Equity awards under EPCO's long-term incentive plans are approved by the ACG Committee of the respective issuer. We do not have a separate compensation committee.

As discussed below, the elements of EPCO's compensation program, along with EPCO's other rewards (e.g., benefits, work environment, career development), are intended to provide a total rewards package to employees. The compensation package is designed to reward contributions by employees in support of the business strategies of EPCO and its affiliates at both the partnership and individual levels.

With respect to the two years ended December 31, 2008, EPCO's compensation package for Named Executive Officers did not include any elements based on targeted performance-related criteria.

The primary elements of EPCO's compensation program are a combination of annual cash and long-term equity-based incentive compensation. For the two years ended December 31, 2008, the elements of compensation for the Named Executive Officers consisted of the following:

- Annual base salary;
- Discretionary annual cash awards;
- Awards under long-term incentive arrangements; and
- Other compensation, including very limited perquisites.

In order to assist Mr. Duncan and EPCO with compensation decisions, Mr. Creel and Mr. Cunningham (both Group Vice Chairmen for EPCO) and the senior vice president of Human Resources for EPCO formulate preliminary compensation recommendations for all of the Named Executive Officers. Mr. Duncan, after consulting with the senior vice president of Human Resources for EPCO, independently makes compensation decisions with respect to our Named Executive Officers. In making these compensation decisions, EPCO considers market data for determining relevant compensation levels and compensation program elements through the review of and, in certain cases, participation in, relevant compensation surveys and reports. These surveys and reports are conducted and prepared by a third party compensation consultant.

Periodically, EPCO will engage a third party consultant to review compensation elements provided to our executive officers. In 2006, EPCO engaged Towers Perrin to review executive compensation relative to our industry. Towers Perrin provided comparative market data on compensation practices and programs for executive level positions based on an analysis of industry competitors. Neither we nor EPCO, which engages the consultant, are aware of the identity of the component companies who supply data to the consultant. EPCO uses the data provided in the Towers Perrin analysis to gauge whether compensation levels reported by the consultant are within the general ranges of compensation for EPCO employees in similar positions, but that comparison is only a factor taken into consideration and may or may not impact compensation of our executive officers, for which Dan L. Duncan has the ultimate decision-making authority. EPCO does not otherwise engage in benchmarking executive level positions.

Mr. Duncan and EPCO do not use any formula or specific performance-based criteria for our Named Executive Officers in connection with determining compensation for services performed for us; rather, Mr. Duncan and EPCO determine an appropriate level and mix of compensation on a case-by-case basis. Further, there is no established policy or target for the allocation between either cash and non-cash or short-term and long-term incentive compensation. However, some considerations that Mr. Duncan may take into account in making the case-by-case compensation determinations include total value of wealth accumulated and the appropriate balance of internal pay equity among executive officers. Mr. Duncan and EPCO also consider individual performance, levels of responsibility, skills and experience. All compensation determinations are discretionary and, as noted above, subject to Mr. Duncan's ultimate decision-making authority, except for equity awards under EPCO's long-term incentive plans, as discussed below.

We believe the absence of specific performance-based criteria associated with our salary compensation and equity awards, and the long-term nature of our equity awards, has the effect of not encouraging excessive risk taking by our executive officers in order to reach certain targets. Further, the practice of making compensation decisions on a case-by-case basis permits consideration of flexible criteria, including current overall market conditions. Because our 2008 annual base salaries and the majority of our 2008 equity awards were made in the first half of 2008, recent market volatility and market declines did not have a material impact on 2008 compensation decisions. However, current market conditions may impact 2009 compensation decisions regarding annual base salaries and equity award grants.

The discretionary cash awards paid to each of our Named Executive Officers were determined by consultation among Mr. Duncan, Mr. Creel, Mr. Cunningham and the senior vice president of Human Resources for EPCO, subject to Mr. Duncan's final determination. These cash awards, in combination with annual base salaries, are intended to yield competitive total cash compensation levels for the Named Executive Officers and drive performance in support of our business strategies, as well as the performance of other EPCO affiliates for which the Named Executive Officers perform services. It is EPCO's general policy to pay these awards in February of each year.

The incentive awards granted under EPCO's long-term incentive plans to our Named Executive Officers were determined by consultation among Mr. Duncan, Mr. Creel and the Senior Vice President of Human Resources for EPCO, and were approved by the ACG Committee of EPGP. Incentive awards issued under EPCO's long-term incentive plans involving securities of Enterprise Products Partners are also approved by the ACG Committee of EPGP. In addition, our Named Executive Officers are Class B limited partners in certain of the Employee Partnerships. Mr. Duncan approves the issuance of all limited partnership interests in the Employee Partnerships to our Named Executive Officers. See "Summary of Long-Term Incentive Arrangements Underlying 2008 Award Grants" within this Item 11 for information regarding the long-term incentive plans. See Note 5 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for information regarding the accounting for such awards.

EPCO generally does not pay for perquisites for any of our Named Executive Officers, other than reimbursement of certain parking expenses, and expects to continue its policy of covering very limited perquisites allocable to our Named Executive Officers. EPCO also makes matching contributions under its 401(k) plan for the benefit of our Named Executive Officers in the same manner as it does for other EPCO employees.

EPCO does not offer our Named Executive Officers a defined benefit pension plan. Also, none of our Named Executive Officers had nonqualified deferred compensation during the two years ended December 31, 2008.

We believe that each of the base salary, cash awards, and incentive awards fit the overall compensation objectives of us and of EPCO, as stated above (i.e., to provide competitive compensation opportunities to align and drive employee performance toward the creation of sustained long-term unitholder value, which will also allow us to attract, motivate and retain high quality talent with the skills and competencies required by us).

Compensation Committee Report

We do not have a separate compensation committee. In addition, we do not directly employ or compensate our Named Executive Officers. Rather, under the ASA with EPCO, we reimburse EPCO for the compensation of our executive officers. Accordingly, to the extent that decisions are made regarding the compensation policies pursuant to which our Named Executive Officers are compensated, they are made by Mr. Duncan and EPCO alone (except for equity awards, as previously noted), and not by our Board.

In light of the foregoing, the Board has reviewed and discussed the Compensation Discussion and Analysis with management and determined that the Compensation Discussion and Analysis be included in the Company's annual report on Form 10-K for the year ended December 31, 2008.

Submitted by: Dan L. Duncan
Richard H. Bachmann
W. Randall Fowler
A.J. Teague

Michael A. Creel
Dr. Ralph S. Cunningham
William A. Bruckmann, III
Larry J. Casey

Notwithstanding anything to the contrary set forth in any previous filings under the Securities Act, as amended, or the Exchange Act, as amended, that incorporate future filings, including this Report, in whole or in part, the foregoing report shall not be incorporated by reference into any such filings.

Grants of Plan-Based Awards in Fiscal Year 2008

The following table presents information concerning each grant of a plan-based award made to a Named Executive Officer in 2008 for which we will be allocated by EPCO our pro rata share under the ASA. The restricted unit and unit option awards granted during 2008 were under the EPCO 1998 Plan and EPD 2008 LTIP. See "Summary of Long-Term Incentive Arrangements Underlying 2008 Award Grants" within this Item 11 for additional information regarding the long-term incentive plans under which these awards were granted.

Name	Grant Date	Estimated Future Payouts Under Equity Incentive Plan Awards Threshold (#)	Target (#)	Maximum (#)	Exercise or Base Price of Option Awards ($/Unit)	Grant Date Fair Value of Unit and Option Awards ($) (1)
Restricted unit awards: (2)						
Richard H. Bachmann (CEO)	5/22/08	--	28,100	--	--	$ 217,283
W. Randall Fowler (CFO)	5/22/08	--	28,100	--	--	$ 108,642
Gil H. Radtke	5/22/08	--	8,600	--	--	$ 66,500
Michael J. Knesek	5/22/08	--	8,600	--	--	$ 53,200
William Ordemann	5/22/08	--	28,100	--	--	$ 34,765
Unit option awards: (3)						
Richard H. Bachmann (CEO)	5/22/08	--	60,000	--	$ 30.93	$ 35,700
W. Randall Fowler (CFO)	5/22/08	--	60,000	--	$ 30.93	$ 17,850
Gil H. Radtke	5/22/08	--	30,000	--	$ 30.93	$ 17,850
Michael J. Knesek	5/22/08	--	30,000	--	$ 30.93	$ 14,280
William Ordemann	5/22/08	--	60,000	--	$ 30.93	$ 5,712
Profits interest awards: (4)						
Enterprise Unit:						
Richard H. Bachmann (CEO)	2/20/08	--	--	--	--	$ 101,785
W. Randall Fowler (CFO)	2/20/08	--	--	--	--	$ 40,399
Gil H. Radtke	2/20/08	--	--	--	--	$ 15,320
Michael J. Knesek	2/20/08	--	--	--	--	$ 40,714
William Ordemann	2/20/08	--	--	--	--	$ 12,928
EPCO Unit:						
Richard H. Bachmann (CEO)	11/13/08	--	--	--	--	$ 349,968
W. Randall Fowler (CFO)	11/13/08	--	--	--	--	$ 174,984
Gil H. Radtke	11/13/08	--	--	--	--	--
Michael J. Knesek	11/13/08	--	--	--	--	--
William Ordemann	11/13/08	--	--	--	--	--

(1) Amounts presented reflect that portion of grant date fair value allocable to us based on the percentage of time each Named Executive Officer spent on our consolidated business activities during 2008. Based on current allocations, we estimate that the consolidated compensation expense we record for each Named Executive Officer with respect to these awards will equal these amounts over time.

(2) For the period in which the restricted unit awards were outstanding during 2008, we recognized a total of $73 thousand of consolidated compensation expense related to these awards. The remaining portion of grant date fair value will be recognized as expense in future periods.

(3) For the period in which the unit option awards were outstanding during 2008, we recognized a total of $14 thousand of consolidated compensation expense related to these awards. The remaining portion of grant date fair value will be recognized as expense in future periods.

(4) For the period in which the profits interest awards were outstanding during 2008, we recognized a total of $34 thousand of consolidated compensation expense related to these awards. The remaining portion of grant date fair value will be recognized as expense in future periods.

The fair value amounts presented in the table are based on certain assumptions and considerations made by management. See Note 5 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for additional information regarding our fair value assumptions.

Summary of Long-Term Incentive Arrangements Underlying 2008 Award Grants

The following information summarizes the types of awards granted to our Named Executive Officers during the year ended December 31, 2008. For detailed information regarding our accounting for equity awards, see Note 5 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

As used in the context of the EPCO, the term "restricted unit" represents a time-vested unit under SFAS 123(R). Such awards are non-vested until the required service period expires.

EPCO 1998 Plan. The EPCO 1998 Plan provides for incentive awards to EPCO's key employees who perform management, administrative or operational functions for us or our affiliates. Awards granted under the EPCO 1998 Plan may be in the form of unit options, restricted units, phantom units and distribution equivalent rights ("DERs").

When issued, the exercise price of each option grant is equivalent to the market price per unit of Enterprise Products Partners' common units on the date of grant. In general, options granted under the EPCO 1998 Plan have a vesting period of four years and remain exercisable for ten years from the date of grant.

A total of 101,500 restricted units were granted under this plan to the Named Executive Officers in May 2008. Restricted unit awards under the EPCO 1998 Plan allow recipients to acquire common units of Enterprise Products Partners (at no cost to the recipient) once a defined vesting period expires, subject to certain 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 Enterprise Products Partners' common units on the date of grant less an allowance for estimated forfeitures. Each recipient is also entitled to cash distributions equal to the product of the number of restricted units outstanding for the participant and the cash distribution per unit paid by Enterprise Products Partners to its unitholders.

The EPCO 1998 Plan also provides for the issuance of phantom unit awards, including related DERs. No phantom unit awards or associated DERs have been granted under the EPCO 1998 Plan.

EPD 2008 LTIP. The EPD 2008 LTIP provides for incentive awards to EPCO's key employees who perform management, administrative or operational functions for us or our affiliates. Awards granted under the EPD 2008 LTIP may be in the form of unit options, restricted units, phantom units and DERs.

A total of 240,000 options were granted under this plan to the Named Executive Officers in May 2008. When issued, the exercise price of each option grant was equivalent to the market price per unit of Enterprise Products Partners' common units on the date of grant. In general, options granted under the EPD 2008 LTIP have a vesting period of four years and are exercisable during specified periods with the calendar year immediately following the year in which vesting occurs. At December 31, 2008, no restricted units, phantom units or DERs had been issued under this plan.

Profits interests awards. Our Named Executive Officers were granted awards consisting of profits interests, or Class B limited partner interests, in Enterprise Unit in February 2008 and EPCO Unit in November 2008. In addition, the Named Executive Officers have received profits interests awards in the other Employee Partnerships in prior years. Profits interest 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 the Named Executive Officers participate own either Parent Company Units or Enterprise Products Partners' common units or a combination of both. Such awards are subject to forfeiture. For additional information regarding the Employee Partnerships, including the assumptions we used to estimate the fair value of these awards, see Note 5 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

The following table presents each Named Executive Officer's share of the total profits interest in the Employee Partnerships at December 31, 2008:

	Percentage Ownership of Class B Interests			
Named Executive Officer	**EPE Unit I**	**EPE Unit III**	**Enterprise Unit**	**EPCO Unit**
Richard H. Bachmann (CEO)	8.2%	7.8%	9.7%	20.0%
W. Randall Fowler (CFO)	5.5%	7.8%	7.8%	20.0%
Michael J. Knesek	2.7%	3.2%	4.8%	--
William Ordemann	2.7%	4.5%	7.8%	--

Mr. Radtke is not included in this table since he was not serving as an executive officer of our general partner at December 31, 2008 and we expect no future allocations of his compensation to be made to us.

Equity Awards Outstanding at December 31, 2008

The following tables present information concerning each Named Executive Officer's long-term incentive awards outstanding at December 31, 2008. We expect to be allocated our pro rata share of the cost of such awards by EPCO under the ASA. As a result, the gross amounts listed in the table do not represent the amount of expense we will recognize in connection with these awards.

The following table presents information concerning each Named Executive Officer's nonvested restricted units and unexercised unit options at December 31, 2008:

		Option Awards			Unit Awards	
Name	Vesting Date	Number of Units Underlying Options Unexercisable (#)	Option Exercise Price ($/Unit)	Option Expiration Date	Number of Units That Have Not Vested (#)(2)	Market Value of Units That Have Not Vested ($)(3)
Restricted unit awards:						
Richard H. Bachmann (CEO)	Various (1)	--	--	--	76,600	$ 1,587,918
W. Randall Fowler (CFO)	Various (1)	--	--	--	63,100	$ 1,308,063
Michael J. Knesek	Various (1)	--	--	--	28,800	$ 597,024
William Ordemann	Various (1)	--	--	--	72,100	$ 1,494,633
Unit option awards:						
Richard H. Bachmann:						
May 10, 2004 option grant	5/10/08	35,000	20.00	5/10/14	--	--
August 4, 2005 option grant	8/04/09	35,000	26.47	8/04/15	--	--
May 1, 2006 option grant	5/01/10	40,000	24.85	5/01/16	--	--
May 29, 2007 option grant	5/29/11	60,000	30.96	5/29/17	--	--
May 22, 2008 option grant	5/22/12	60,000	30.93	12/31/13	--	--
W. Randall Fowler (CFO):						
May 10, 2004 option grant	5/10/08	10,000	20.00	5/10/14	--	--
August 4, 2005 option grant	8/04/09	25,000	26.47	8/04/15	--	--
May 1, 2006 option grant	5/01/10	40,000	24.85	5/01/16	--	--
May 29, 2007 option grant	5/29/11	45,000	30.96	5/29/17	--	--
May 22, 2008 option grant	5/22/12	60,000	30.93	12/31/13	--	--
Michael J. Knesek:						
May 10, 2004 option grant	5/10/08	10,000	20.00	5/10/14	--	--
August 4, 2005 option grant	8/04/09	15,000	26.47	8/04/15	--	--
May 1, 2006 option grant	5/01/10	30,000	24.85	5/01/16	--	--
May 29, 2007 option grant	5/29/11	30,000	30.96	5/29/17	--	--
May 22, 2008 option grant	5/22/12	30,000	30.93	12/31/13	--	--
William Ordemann:						
May 10, 2004 option grant	5/10/08	25,000	20.00	5/10/14	--	--
August 4, 2005 option grant	8/04/09	25,000	26.47	8/04/15	--	--
May 1, 2006 option grant	5/01/10	30,000	24.85	5/01/16	--	--
May 29, 2007 option grant	5/29/11	30,000	30.96	5/29/17	--	--
May 22, 2008 option grant	5/22/12	60,000	30.93	12/31/13	--	--

(1) Of the 240,600 restricted unit awards presented in the table, 37,000 vest in 2009, 38,400 vest in 2010, 72,300 vest in 2011 and 92,900 vest in 2012.

(2) Amounts represent total number of restricted unit awards granted to Named Executive Officer.

(3) Amounts derived by multiplying the total number of restricted unit awards granted to the Named Executive Officer by the closing price of Enterprise Products Partners' common units at December 31, 2008 of $20.73 per unit.

The following table presents information concerning each Named Executive Officer's nonvested profits interest awards at December 31, 2008:

Name	Vesting Date	Option Awards: Number of Units Underlying Options Unexercisable (#)	Option Awards: Option Exercise Price ($/Unit)	Option Awards: Option Expiration Date	Unit Awards: Number of Units That Have Not Vested (#)	Unit Awards: Market Value of Units That Have Not Vested ($)
EPE Unit I:						
Richard H. Bachmann (CEO)	11/09/12	--	--	--	--	$ 0
W. Randall Fowler (CFO)	11/09/12	--	--	--	--	$ 0
Michael J. Knesek	11/09/12	--	--	--	--	$ 0
William Ordemann	11/09/12	--	--	--	--	$ 0
EPE Unit III:						
Richard H. Bachmann (CEO)	5/09/14	--	--	--	--	$ 0
W. Randall Fowler (CFO)	5/09/14	--	--	--	--	$ 0
Michael J. Knesek	5/09/14	--	--	--	--	$ 0
William Ordemann	5/09/14	--	--	--	--	$ 0
Enterprise Unit:						
Richard H. Bachmann (CEO)	2/20/14	--	--	--	--	$ 0
W. Randall Fowler (CFO)	2/20/14	--	--	--	--	$ 0
Michael J. Knesek	2/20/14	--	--	--	--	$ 0
William Ordemann	2/20/14	--	--	--	--	$ 0
EPCO Unit:						
Richard H. Bachmann (CEO)	11/13/13	--	--	--	--	$ 0
W. Randall Fowler (CFO)	11/13/13	--	--	--	--	$ 0
Michael J. Knesek	11/13/13	--	--	--	--	$ 0
William Ordemann	11/13/13	--	--	--	--	$ 0

The profits interest awards had no market (or assumed liquidation) value at December 31, 2008 due to a decrease in the market value of the limited partner interests owned by each Employee Partnership since the formation

Mr. Radtke is not included in the preceding two tables since he was not serving as an executive officer of our general partner at December 31, 2008 and we expect no future allocations of his compensation to be made to us.

Option Exercises and Stock Vested

The following table presents the exercise of unit options by and vesting of restricted units to our Named Executive Officers during the year ended December 31, 2008 for which we were historically responsible for a share of the related cost of such awards.

Name	Option Awards: Number of Units Acquired on Exercise (#)	Option Awards: Value Realized on Exercise ($)	Unit Awards: Number of Units Acquired on Vesting (#	Unit Awards: Gross Value Realized on Vesting ($) (1)
Richard H. Bachmann (CEO)	--	--	54,553	$ 1,146,990
W. Randall Fowler (CFO)	--	--	23,777	$ 467,209
Gil H. Radtke	--	--	6,000	$ 182,220
Michael J. Knesek	--	--	15,266	$ 310,691
William Ordemann	--	--	6,000	$ 182,220

(1) Amount determined by multiplying the number of restricted unit awards that vested during 2008 by the closing price of Enterprise Products Partners' common units on the date of vesting.

Director Compensation

The following table presents information regarding compensation to the independent directors of our general partner during the year ended December 31, 2008.

Name	Fees Earned or Paid in Cash ($)	Unit Awards ($)	Unit Appreciation Rights ($) (1)	Total ($)
William A. Bruckmann, III	$ 90,000	--	$ 415	$ 90,415
Joe D. Havens	$ 75,000	--	$ 415	$ 75,415
Larry J. Casey	$ 75,000	--	$ 415	$ 75,415

(1) Amounts presented reflect compensation expense recognized in accordance with SFAS 123(R) by DEP GP.

Neither we nor DEP GP provide any additional compensation to employees of EPCO who serve as directors of DEP GP. DEP GP's three independent directors, Messrs. Casey, Havens and Bruckmann, are provided cash compensation for their services as follows:

§ Each independent director receives $75,000 in cash annually.

§ If the individual serves as chairman of a committee of the Board of Directors, then he receives an additional $15,000 in cash annually.

In addition to cash compensation, Messrs. Bruckmann, Casey and Havens were granted 30,000 UARs each in February 2007 that entitle them to receive a cash amount in the future equal to the excess, if any, of the fair market value of Enterprise GP Holdings' units (determined as of a future vesting date) over the grant date price of such units. The awards were in the form of letter agreements and based upon an incentive plan of the general partner of Enterprise GP Holdings (i.e., UAR grants for non-employee directors). If a director resigns or is removed prior to vesting, his UAR awards are forfeited. The compensation expense associated with these liability awards is recognized by DEP GP.

The grant date price of the UARs was $36.68 per unit. These awards vest in February 2012 or the date of certain qualifying events (as set forth in the form of grant). At December 31, 2008, the total fair value of these 90,000 UARs was approximately $30 thousand, which was based on the following assumptions: (i) remaining life of award of three years; (ii) risk-free interest rate of 1.0%; (iii) an expected distribution yield on Enterprise GP Holdings' units of 5.4%; and (iv) an expected unit price volatility of Enterprise GP Holdings' units of 30.3%.

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

Security Ownership of Certain Beneficial Owners

The following table sets forth certain information as of February 2, 2009, regarding each person known by our general partner to beneficially own more than 5% of our common units.

Title of Class	Name and Address of Beneficial Owner	Amount and Nature of Beneficial Ownership	Percent of Class
Common units	Enterprise Products Operating LLC 1100 Louisiana Street, 10th Floor Houston, Texas 77002	42,726,987	74.1%

Security Ownership of Management

The following table sets forth certain information regarding the beneficial ownership of our common units and the common units of Enterprise Products Partners L.P. as of February 2, 2009 by (i) our Named Executive Officers, (ii) the current directors of DEP GP and (iii) the current directors and executive officers of DEP GP as a group. Enterprise Products Partners L.P. owns 100% of the member interests of EPO, which in turn owns 100% of DEP GP and 74.1% of our common units as of February 2, 2009. EPO also retains varying ownership interests in the DEP I and DEP II Midstream Businesses.

All beneficial ownership information has been furnished by the respective directors or officers. Each person has sole voting and dispositive power over the securities shown unless indicated otherwise. The beneficial ownership amounts of certain individuals include options to acquire common units of Enterprise Products Partners L.P. that are exercisable within 60 days of the filing date of this annual report.

Mr. Duncan owns 50.4% of the voting stock of EPCO and, accordingly, exercises sole voting and dispositive power with respect to the common units of Enterprise Products Partners L.P. that are beneficially owned by EPCO and its affiliates. The remaining shares of EPCO capital stock are owned primarily by trusts for the benefit of Mr. Duncan's family. The address of EPCO is 1100 Louisiana Street, 10th Floor, Houston, Texas 77002.

	Duncan Energy Partners L.P. Common Units		Enterprise Products Partners L.P. Common Units	
Name of Beneficial Owner	**Amount and Nature Of Beneficial Ownership**	**Percent of Class**	**Amount and Nature Of Beneficial Ownership**	**Percent of Class**
Dan L. Duncan:				
Units owned by EPCO:				
Through DFI Delaware Holdings, L.P.	--	--	121,990,717	27.0%
Through Enterprise GP Holdings L.P.	--	--	13,670,925	3.0%
Through EPCO Holdings, Inc	--	--	1,037,037	*
Units owned by EPO	42,726,987	74.1%	--	--
Units owned by DD Securities LLC	103,100	*	487,100	*
Units owned by Employee Partnerships (1)	--	--	1,623,654	*
Units owned by family trusts (2)	--	--	12,517,338	2.8%
Units owned personally	282,500	*	1,179,756	*
Total for Dan L. Duncan	43,112,587	74.7%	152,506,527	33.8%
Richard H. Bachmann (CEO) (3)	10,171	*	190,822	*
W. Randall Fowler (CFO) (3)	2,000	*	105,300	*
A. James Teague	6,000	*	252,323	*
Michael A. Creel	7,500	*	195,842	*
Dr. Ralph S. Cunningham	3,000	*	76,847	*
Larry J. Casey	10,900	*	--	--
Joe D. Havens	109,322	*	259,233	*
William A. Bruckmann, III	4,500	*	--	--
William Ordemann (3)	3,810	*	116,871	*
Michael J. Knesek (3)	1,340	*	49,871	*
All current directors and executive officers of DEP GP, as a group (11 individuals in total) (4)	43,271,130	75.0%	153,753,636	34.0%

* Represents a beneficial ownership of less than 1% of class

(1) As a result of EPCO's ownership of the general partners of the Employee Partnerships, Mr. Duncan is deemed beneficial owner of the limited partner interests held by these entities.

(2) Mr. Duncan is deemed beneficial owner of the limited partner interests held by certain family trusts, the beneficiaries of which are shareholders of EPCO.

(3) These individuals are Named Executive Officers.

(4) Cumulatively, this group's beneficial ownership amount includes 115,000 options to acquire Enterprise Products Partners common units that were issued under the EPCO 1998 Plan. These options vested in prior periods and remain exercisable within 60 days of the filing date of this annual report.

The preceding table does not present any information for Gil H. Radtke, who was one of our Named Executive Officers for 2008.   Mr. Radtke resigned from EPCO in January 2009.

Securities Authorized for Issuance Under Equity Compensation Plans

Duncan Energy Partners L.P. does not have any of its securities authorized for issuance under equity compensation plans as of December 31, 2008.

Item 13. ***Certain Relationships and Related Transactions, and Director Independence.***

Related Party Transactions

The following information summarizes our business relationships and transactions with related parties during the year ended December 31, 2008. 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.

The following table summarizes our consolidated revenue and expense transactions with related parties for the periods indicated:

	For the Year Ended December 31,		
	2008	2007	2006
Revenues:			
Revenues from EPO:			
Sales of natural gas	$ 165,984	$ 22,762	$ 59,036
Natural gas transportation services	32,283	21,846	11,681
Natural gas storage services	875	--	66
Sales of NGLs	52,909	41,226	35,856
NGL and petrochemical storage services	33,774	28,853	20,113
NGL fractionation services	28,345	30,253	29,629
NGL transportation services	22,981	27,239	10,115
Other natural gas and NGL related services	39,323	24,134	59,745
Sales of natural gas – Evangeline	362,890	264,248	277,741
Natural gas transportation services – Energy Transfer Equity	903	437	--
NGL and petrochemical storage services – TEPPCO	1,381	40	26
Total related party revenues	$ 741,648	$ 461,038	$ 504,008
Operating costs and expenses:			
EPCO administrative services agreement	$ 72,048	$ 63,710	$ 65,474
Expenses with EPO:			
Purchases of natural gas	229,932	29,071	12,355
Operational measurement losses (gains)	6,831	(4,537)	--
Other expenses with EPO	18,619	7,480	(1)
Purchases of natural gas – Nautilus	10,250	3,531	1,573
Expenses with Energy Transfer Equity:			
Purchases of natural gas	7,294	5,628	--
Operating cost reimbursements for shared facilities	(2,789)	(1,746)	--
Other expenses with Energy Transfer Equity	3,133	1,088	--
Expenses with TEPPCO	(194)	(74)	(154)
Other related party expenses, primarily with Evangeline	14	110	2
Total related party operating costs and expenses	$ 345,138	$ 104,261	$ 79,249
General and administrative costs:			
EPCO administrative services agreement	$ 15,663	$ 11,480	$ 10,157
Other related party general and administrative costs	(781)	(65)	--
Total related party general and administrative costs	$ 14,882	$ 11,415	$ 10,157

One of our principal advantages is our relationship with EPO and EPCO. EPO is a wholly owned subsidiary of Enterprise Products Partners through which Enterprise Products Partners conducts its business. Enterprise Products Partners is controlled by its general partner, Enterprise Products GP, LLC ("EPGP"), which in turn is a wholly owned subsidiary of Enterprise GP Holdings. The general partner of Enterprise GP Holdings is EPE Holdings, LLC ("EPE Holdings"), which is a wholly owned subsidiary of a private company controlled by Dan L. Duncan (see Item 10). Mr. Duncan is Chairman of our general partner and is a Group Co-Chairman and the controlling shareholder of EPCO. Our general partner is wholly owned by EPO and EPCO provides all of our employees, including our executive officers.

Relationship 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 growth objectives of EPO and other affiliates under common control.

At December 31, 2008, EPO owned approximately 74% of our limited partner interests and our general partner. EPO was sponsor of the DEP I and DEP II dropdown 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 dropdown transactions (including consideration provided to EPO), see the related sections under "Overview of Business" under Item 7 of this annual report. For a description of EPO's Parent interest in the income and net assets of the DEP I and DEP II Midstream Businesses, see "Parent Interest in Subsidiaries" under Item 7 of this annual report. 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.

A significant portion of our related party revenues from EPO are attributable to the sale of natural gas and NGLs and the provision of storage services. For 2008, EPO accounted for 23.6% of our consolidated revenues. Our related party expenses with EPO primarily involve the purchase of natural gas by Acadian Gas. Acadian Gas sells natural gas to Evangeline (an unconsolidated affiliate - see "Relationship with Evangeline" within this Item 13) that, in turn, enables Evangeline to meet its commitment under a sales contract with a third party utility customer.

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 dropdown 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 (estimated at $1.4 million) 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 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 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 dropdown transactions. These indemnifications terminate 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, 2008 and 2007.

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 "Parent Interest in Subsidiaries – DEP I Midstream Businesses" under Item 7 of this annual report.

Mont Belvieu Caverns' LLC Agreement. The 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 projects 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 "Parent Interest in Subsidiaries – DEP I Midstream Businesses" under Item 7 of this annual report.

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 dropdown transaction. Collectively, these amended and restated agreements provide for the following:

- § the acquisition by Enterprise III (our wholly owned subsidiary) from Enterprise GTM (a wholly owned subsidiary of 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 Enterprise III (based on an initial defined investment of $730.0 million, the "Enterprise III Distribution Base") and then to Enterprise GTM (based on an initial defined investment of $452.1 million, the "Enterprise GTM Distribution Base") 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% to Enterprise GTM and 2% to Enterprise III. 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, Enterprise III has elected to not participate in such cash calls and, as a result, Enterprise GTM has funded 100% of the expansion project costs of the DEP II Midstream Businesses. If Enterprise III later elects to participate in an expansion projects, then Enterprise III will be required to make a capital contribution for its share of the project costs.

Any capital contributions to fund expansion projects made by either Enterprise III or Enterprise GTM will increase such partner's Distribution Base (and hence future priority return amounts) under the Company Agreement of Enterprise Texas. As noted, Enterprise III has declined participation in expansion project spending since December 8, 2008. As a result, Enterprise GTM has funded 100% of such growth capital spending and its Distribution Base has increased from $452.1 million at December 8, 2008 to $473.4 million at December 31, 2008. The Enterprise III Distribution Base was unchanged at $730.0 million at December 31, 2008.

Relationship with EPCO

We have no employees. All of our operating functions and general and administrative support services are provided by employees of EPCO pursuant to the ASA. We, Enterprise Products Partners, Enterprise GP Holdings, TEPPCO 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 for the year ended December 31, 2008 include reimbursement payments 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. Such reimbursements were $72.0 million during the year ended December 31, 2008.

Likewise, our general and administrative costs for the year ended December 31, 2008 includes amounts we reimburse 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 legal or accounting salaries based on estimates of time spent on each entity's business and affairs). Such reimbursements were $15.7 million during the year ended December 31, 2008.

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. With respect to potential conflicts, the ASA provides, among other things, that:

§ If a business opportunity to acquire "equity securities" (as defined below) is presented to the EPCO Group, Enterprise Products Partners (including EPGP), Enterprise GP Holdings (including EPE Holdings), Duncan Energy Partners (including DEP GP), then Enterprise GP Holdings will have the first right to pursue such opportunity. The term "equity securities" is defined to include:

  § general partner interests (or securities which have characteristics similar to general partner interests) or interests in "persons" that own or control such general partner or similar interests (collectively, "GP Interests") and securities convertible, exercisable, exchangeable or otherwise representing ownership or control of such GP Interests; and

  § incentive distribution rights and limited partner interests (or securities which have characteristics similar to incentive distribution rights or limited partner interests) in publicly traded partnerships or interests in "persons" that own or control such limited partner or similar interests (collectively, "non-GP Interests"); provided that such non-GP Interests are associated with GP Interests and are owned by the owners of GP Interests or their respective affiliates.

Enterprise GP Holdings will be presumed to want to acquire the equity securities until such time as EPE Holdings advises the EPCO Group, EPGP and DEP GP that it has abandoned the pursuit of such business opportunity. In the event that the purchase price of the equity securities is reasonably likely to equal or exceed $100 million, the decision to decline the acquisition will be made by the Chief Executive Officer of EPE Holdings after consultation with and subject to the approval of the ACG Committee of EPE Holdings. If the purchase price is reasonably likely to be less than $100 million, the Chief Executive Officer of EPE Holdings may make the determination to decline the acquisition without consulting the ACG Committee of EPE Holdings.

In the event that Enterprise GP Holdings abandons the acquisition and so notifies the EPCO Group, EPGP and DEP GP, Enterprise Products Partners will have the second right to pursue such acquisition. Enterprise Products Partners will be presumed to want to acquire the equity securities until such time as EPGP advises the EPCO Group and DEP GP that Enterprise Products Partners has abandoned the pursuit of such acquisition. In determining whether or not to pursue the acquisition, Enterprise Products Partners will follow the same procedures applicable to Enterprise GP Holdings, as described above but utilizing EPGP's Chief Executive Officer and ACG Committee.

In its sole discretion, Enterprise Products Partners may affirmatively direct such acquisition opportunity to Duncan Energy Partners. In the event this occurs, Duncan Energy Partners may pursue such acquisition.

In the event Enterprise Products Partners abandons the acquisition opportunity for the equity securities and so notifies the EPCO Group and DEP GP, the EPCO Group may pursue the acquisition or offer the opportunity to TEPPCO (including its general partner) and their controlled affiliates, in either case, without any further obligation to any other party or offer such opportunity to other affiliates.

§ If any business opportunity not covered by the preceding bullet point (i.e. not involving "equity securities") is presented to the EPCO Group, Enterprise Products Partners (including EPGP), Enterprise GP Holdings (including EPE Holdings), or Duncan Energy Partners (including DEP GP), Enterprise Products Partners will have the first right to pursue such opportunity either for itself or, if desired by Enterprise Products Partners in its sole discretion, for the benefit of Duncan Energy Partners. It will be presumed that Enterprise Products Partners will pursue the business opportunity until such time as its general partner advises the EPCO Group, EPE Holdings and DEP GP that it has abandoned the pursuit of such business opportunity.

In the event the purchase price or cost associated with the business opportunity is reasonably likely to equal or exceed $100 million, any decision to decline the business opportunity will be made by the Chief Executive Officer of EPGP after consultation with and subject to the approval of the ACG Committee of EPGP. If the purchase price or cost is reasonably likely to be less than $100 million, the Chief Executive Officer of EPGP may make the determination to decline the business opportunity without consulting EPGP's ACG Committee.

In its sole discretion, Enterprise Products Partners may affirmatively direct such acquisition opportunity to Duncan Energy Partners. In the event this occurs, Duncan Energy Partners may pursue such acquisition.

In the event that Enterprise Products Partners abandons the business opportunity for itself and Duncan Energy Partners and so notifies the EPCO Group, EPE Holdings and DEP GP, Enterprise GP Holdings will have the second right to pursue such business opportunity. It will be presumed that Enterprise GP Holdings will pursue such acquisition until such time as its general partner declines such opportunity (in accordance with the procedures described above for Enterprise Products Partners) and advises the EPCO Group that it has abandoned the pursuit of such business opportunity. Should this occur, the EPCO Group may either pursue the business opportunity or offer the business opportunity to TEPPCO (including its general partner) and their controlled affiliates without any further obligation to any other party or offer such opportunity to other affiliates.

None of Enterprise Products Partners, Enterprise GP Holdings, Duncan Energy Partners or their respective general partners or the EPCO Group have any obligation to present business opportunities to TEPPCO (including its general partner) or their controlled affiliates. Likewise, TEPPCO (including its general partner) and their controlled affiliates have no obligation to present business opportunities to Enterprise Products Partners, Enterprise GP Holdings, Duncan Energy Partners or their respective general partners or the EPCO Group.

The ASA was amended on January 30, 2009 to provide for the cash reimbursement by us, Enterprise Products Partners, TEPPCO 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.

Employee Partnerships. EPCO formed the Employee Partnerships to serve as an incentive arrangement for key employees of EPCO by providing them a "profits interest" in such partnerships. Certain EPCO employees who work on behalf of us and EPCO were issued Class B limited partner interests and admitted as Class B limited partners of the Employee Partnerships without any capital contribution. The profits interest awards (i.e., the Class B limited partner interests) in the Employee Partnerships entitle the holder to participate in the appreciation in value of the underlying limited partner interest owned by the Employee Partnership. For additional information regarding the Employee Partnerships, see Note 5 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Relationship with Evangeline

Evangeline has entered into a natural gas purchase contract with Acadian Gas that contains annual purchase provisions. The pricing terms of the purchase agreement are based on a monthly weighted-average market price of natural gas (subject to certain market index price ceilings and incentive margins) plus a predetermined margin. Acadian Gas sold $362.9 million, $264.2 million and $277.7 million of natural gas to Evangeline during the years ended December 31, 2008, 2007 and 2006, respectively. The amount of natural gas purchased by Evangeline pursuant to this contract was 36.9 BBtus during the year ended December 31, 2008 and 36.8 BBtus during each of the years ended December 31, 2007 and 2006. Evangeline was our largest customer and accounted for 22.7% of our consolidated revenues in 2008.

EPO has furnished letters of credit on behalf of Evangeline's debt service requirements. The outstanding letters of credit totaled $1.0 million at December 31, 2008.

Relationship with Energy Transfer Equity

Enterprise GP Holdings acquired equity method investments in Energy Transfer Equity, L.P. ("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 and its consolidated subsidiaries became related parties 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.

Relationship 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.

Review and Approval of Transactions with Related Parties

We generally consider transactions between us and our subsidiaries, on the one hand, and our executive officers and directors (or their immediate family members), our General Partner or its affiliates (including companies owned or controlled by Mr. Duncan such as EPCO), on the other hand, to be related party transactions. As further described below, our Partnership Agreement sets forth procedures by which related party transactions and conflicts of interest may be approved or resolved by the General Partner or the ACG Committee. In addition, our ACG Committee Charter, our General Partner's written internal review and approval policies and procedures, or "management authorization policy," and the ASA with EPCO govern specified related party transactions, as further described below.

The ACG Committee Charter provides that the ACG Committee is established to review and approve related party transactions:

- § for which Board approval is required by our management authorization policy, as such policy may be amended from time to time;
- § where an officer or director of the General Partner or any of our subsidiaries is a party, without regard to the size of the transaction;
- § when requested to do so by management or the Board; or
- § pursuant to our Partnership Agreement or the limited liability company agreement of the General Partner, as such agreements may be amended from time to time.

As discussed in more detail in "Item 10. Directors, Executive Officers and Corporate Governance —Partnership Management", "— Corporate Governance" and "—ACG Committee," the ACG Committee is comprised of three directors: William A Bruckmann, Joe D. Havens and Larry J. Casey. During the year ended December 31, 2008, the ACG Committee reviewed and approved the DEP II dropdown transaction. In reviewing and approving the DEP II dropdown transaction, the ACG Committee retained its own counsel and received a fairness opinion from an independent financial advisor.

Our management authorization policy currently requires board approval for the following types of transactions to the extent such transactions have a value in excess of $100 million (thus triggering ACG Committee review under our ACG Committee Charter if such transaction is also a related party transaction):

- § asset purchase or sale transactions;
- § capital expenditures; and
- § purchase orders and operating and administrative expenses not governed by the ASA.

The ASA governs numerous day-to-day transactions between us and our subsidiaries, our General Partner and EPCO and its affiliates, including the provision by EPCO of administrative and other services to us and our subsidiaries and our reimbursement of costs, without markup or discount, for those services.

The ACG Committee reviewed and recommended the ASA, and the Board approved it upon receiving such recommendation.

Related party transactions that do not occur under the ASA and that are not reviewed by the ACG Committee, as described above, are subject to the management authorization policy. This policy, which applies to related party transactions as well as transactions with unrelated parties, specifies thresholds for our General Partner's officers and Chairman of the Board to authorize various categories of transactions, including purchases and sales of assets, expenditures, commercial and financial transactions and legal agreements.

Partnership Agreement Standards for ACG Committee Review

Under our partnership agreement, unless otherwise expressly provided therein or in the partnership agreement of EPO, whenever a potential conflict of interest exists or arises between our general partner or any of its affiliates, on the one hand, and us, any of our subsidiaries or any partner, on the other hand, any resolution or course of action by our general partner or its affiliates in respect of such conflict of interest is permitted and deemed approved by all of our partners, and will not constitute a breach of our partnership agreement, the partnership agreement of EPO or any agreement contemplated by such agreements, or of any duty stated or implied by law or equity, if the resolution or course of action is or, by operation of the partnership agreement is deemed to be, fair and reasonable to us; provided that, any conflict of interest and any resolution of such conflict of interest will be conclusively deemed fair and reasonable to us if such conflict of interest or resolution is (i) approved by a majority of the members of our general partner's ACG

Committee (i.e., a “Special Approval”), or (ii) on terms objectively demonstrable to be no less favorable to us than those generally being provided to or available from third parties.

In connection with its resolution of any conflict of interest, our general partner’s ACG Committee (through its Special Approval process) is authorized to consider:

- the relative interests of any party to such conflict, agreement, transaction or situation and the benefits and burdens relating to such interest;
- the totality of the relationships between the parties involved (including other transactions that may be particularly favorable or advantageous to us);
- any customary or accepted industry practices and any customary or historical dealings with a particular person;
- any applicable generally accepted accounting or engineering practices or principles;
- the relative cost of capital of the parties and the consequent rates of return to the equity holders of the parties; and
- such additional factors as the ACG Committee determines in its sole discretion to be relevant, reasonable or appropriate under the circumstances.

The review and approval process of the ACG Committee, including factual matters that may be considered in determining whether a transaction is fair and reasonable to us, is generally governed by Section 7.9 of our partnership agreement. As discussed above, the ACG Committee’s Special Approval is conclusively deemed fair and reasonable to us under our partnership agreement.

Director Independence

Messrs. Casey, Havens and Bruckmann have been determined to be independent under the applicable NYSE listing standards and are independent under the rules of the SEC applicable to audit committees. For a discussion of independence standards applicable to the Board and factors considered by the Board in making its independence determinations, please refer to “Corporate Governance – ACG Committee” under Item 10 of this annual report.

Item 14. ***Principal Accountant Fees and Services.***

We have engaged Deloitte & Touche LLP, the member firms of Deloitte Touche Tohmatsu, and their respective affiliates (collectively, "Deloitte & Touche") as our independent registered public accounting firm and principal accountants. The following table summarizes fees we and Duncan Energy Partners Predecessor paid Deloitte & Touche for independent auditing, tax and related services for each of the last two fiscal years (dollars in thousands):

	For The Year Ended December 31, 2008	For The Year Ended December 31, 2007
Audit Fees (1)	$ 915	$ 465
Audit-Related Fees (2)	--	8
Tax Fees (3)	231	34
All Other Fees (4)	n/a	n/a

(1) Audit fees represent amounts billed for each of the years presented for professional services rendered in connection with (i) the audit of our annual financial statements and internal controls over financial reporting, (ii) the review of our quarterly financial statements or (iii) those services normally provided in connection with statutory and regulatory filings or engagements including comfort letters, consents and other services related to SEC matters. This information is presented as of the latest practicable date for this annual report.

(2) Audit-related fees represent amounts we were billed in each of the years presented for assurance and related services that are reasonably related to the performance of the annual audit or quarterly reviews. This category primarily includes services relating to internal control assessments and accounting-related consulting.

(3) Tax fees represent amounts we were billed in each of the years presented for professional services rendered in connection with tax compliance, tax advice, and tax planning. This category primarily includes services relating to the preparation of unitholder annual K-1 statements, partnership tax planning and property tax assistance. In 2008, PricewaterhouseCoopers International Limited was engaged to perform the majority of tax related services.

(4) All other fees represent amounts we were billed in each of the years presented for services not classifiable under the other categories listed in the table above. No such services were rendered by Deloitte & Touche during the years ended December 31, 2008 and 2007.

The ACG Committee of DEP GP has approved the use of Deloitte & Touche as our independent principal accountant. In connection with its oversight responsibilities, the ACG Committee has adopted a pre-approval policy regarding any services proposed to be performed by Deloitte & Touche. The pre-approval policy includes four primary service categories: Audit, Audit-related, Tax and Other.

In general, as services are required, management and Deloitte & Touche submit a detailed proposal to the ACG Committee discussing the reasons for the request, the scope of work to be performed, and an estimate of the fee to be charged by Deloitte & Touche for such work. The ACG Committee discusses the request with management and Deloitte & Touche, and if the work is deemed necessary and appropriate for Deloitte & Touche to perform, approves the request subject to the fee amount presented (the initial "pre-approved" fee amount). As part of these discussions, the ACG Committee must determine whether or not the proposed services are permitted under the rules and regulations concerning auditor independence under the Sarbanes-Oxley Act of 2002 as well as rules of the American Institute of Certified Public Accountants. If at a later date, it appears that the initial pre-approved fee amount may be insufficient to complete the work, then management and Deloitte & Touche must present a request to the ACG Committee to increase the approved amount and the reasons for the increase.

Under the pre-approval policy, management cannot act upon its own to authorize an expenditure for services outside of the pre-approved amounts. On a quarterly basis, the ACG Committee is provided a schedule showing Deloitte & Touche's pre-approved amounts compared to actual fees billed for each of the primary service categories. The ACG Committee's pre-approval process helps to ensure the independence of our principal accountant from management.

In order for Deloitte & Touche to maintain its independence, we are prohibited from using them to perform general bookkeeping, management or human resource functions, and any other service not permitted by the Public Company Accounting Oversight Board. The ACG Committee's pre-approval policy also precludes Deloitte & Touche from performing any of these services for us.

PART IV

Item 15. *Exhibits and Financial Statement Schedules.*

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

(1) Financial Statements: See Index to Consolidated Financial Statements on page F-1 of this Report for financial statements filed as part of this 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. The agreements included as exhibits are included only to provide information to investors regarding their terms. The agreements listed below may contain representations, warranties and other provisions that were made, among other things, to provide the parties thereto with specified rights and obligations and to allocate risk among them, and such agreements should not be relied upon as constituting or providing any factual disclosures about us, any other persons, any state of affairs or other matters.

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	First Amendment to Amended and Restated Partnership Agreement of Duncan Energy Partners L.P. dated as of December 27, 2007 (incorporated by reference to Exhibit 3.1 to Form 8-K/A filed January 3, 2008).
3.4	Third Amendment to Amended and Restated Partnership Agreement 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).
3.5	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 for the period ended March 31, 2007, filed on May 4, 2007).
3.6	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).
3.7	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).
3.8	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).
3.9	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).
4.1	Revolving Credit Agreement, dated as of January 5, 2007, among Duncan Energy Partners L.P., as borrower, 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 10.20 to Amendment No. 2 to Form S-1 Registration Statement (Reg. No. 333-138371) filed January 12, 2007).
4.2	First Amendment to Revolving Credit Agreement, dated as of June 30, 2007, among Duncan Energy Partners L.P., as borrower, 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 the Form 10-Q filed on August 8, 2007).
4.3	Term Loan Agreement, dated as of April 18, 2008, among Duncan Energy Partners L.P., the lenders party thereto, Wachovia Bank, National Association, as Administrative Agent, Suntrust Bank and The Bank of Nova Scotia, as Co-Syndication Agents, and Mizuho Corporate Bank, Ltd. and The Royal Bank of Scotland plc, as Co-Documentation Agents (incorporated by reference to Exhibit 10.7 of Form 8-K filed December 8, 2008).
4.4	First Amendment to Term Loan Agreement, dated as of July 11, 2008, among Duncan Energy Partners L.P., Wachovia Bank, National Association, as Administrative Agent, and the Lenders party thereto (incorporated by reference to Exhibit 10.8 of Form 8-K filed December 8, 2008).
10.1***	Amended and Restated Enterprise Products 2008 Long-Term Incentive Plan (incorporated by reference to Exhibit 4.1 to the Form S-8 filed by Enterprise Products Partners L.P. on May 6, 2008).
10.2***	Form of Option Grant Award under Enterprise Products 2008 Long-Term Incentive Plan (incorporated by reference to Exhibit 4.3 to the Form S-8 filed by Enterprise Products Partners L.P. on May 6, 2008).
10.3***	Form of Restricted Unit Grant Award under Enterprise Products 2008 Long-Term Incentive Plan (incorporated by reference to Exhibit 4.2 to the Form S-8 filed by Enterprise Products Partners L.P. on May 6, 2008).
10.4***	Form of Option Grant Award under Enterprise Products 1998 Long-Term Incentive Plan for awards issued after May 7, 2008 (incorporated by reference to Exhibit 10.4 to the Form 10-Q filed by Enterprise Products Partners L.P. on May 12, 2008).
10.5***	Amendment to Form of Option Grant Award under Enterprise Products 1998 Long-Term Incentive Plan for awards issued after April 10, 2007 but before May 7, 2008 (incorporated by reference to Exhibit 10.5 to the Form 10-Q filed by Enterprise Products Partners L.P. on May 12, 2008).
10.6***	Form of Restricted Unit Grant under the Enterprise Products 1998 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.3 to Form 10-Q filed by Enterprise Products Partners L.P. on November 9, 2007).
10.7***	Enterprise Unit L.P. Agreement of Limited Partnership dated February 20, 2008 (incorporated by reference to Exhibit 10.1 to the Form 8-K filed by Enterprise Products Partners L.P. on February 26, 2008).
10.8***	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).
10.9***	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).
10.10***	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).
10.11***	EPCO Unit L.P. Agreement of Limited Partnership dated November 13, 2008 (incorporated by reference to Exhibit 10.5 to the Form 8-K filed by Enterprise Products Partners L.P. on November 18, 2008).
10.12	Second Amended and Restated Limited Liability Company Agreement of Mont Belvieu Caverns, LLC, dated November 6, 2008 (incorporated by reference to Exhibit 10.4 to Form 10-Q for the period ended September 30, 2008, filed on November 10, 2008)

10.13	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 the Seller Parties and (b) Duncan Energy Partners L.P., DEP Holdings, LLC, DEP Operating Partnership, L.P. and DEP OLP GP, LLC as the Buyer Parties (incorporated by reference to Exhibit 10.1 of Form 8-K filed December 8, 2008).
10.14	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).
10.15	Third Amended and Restated Agreement of Limited Partnership of Enterprise GC, L.P. dated as of December 8, 2008 (incorporated by reference to Exhibit 10.3 of Form 8-K filed December 8, 2008).
10.16	Fourth Amended and Restated Agreement of Limited Partnership of Enterprise Intrastate L.P. dated as of December 8, 2008 (incorporated by reference to Exhibit 10.4 of Form 8-K filed December 8, 2008).
10.17	Amended and Restated Company Agreement of Enterprise Texas Pipeline LLC dated as of December 8, 2008 (incorporated by reference to Exhibit 10.5 of Form 8-K filed December 8, 2008).
10.18	Amended and Restated Omnibus Agreement dated as of 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, L.L.C., 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).
10.19	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).
12.1#	Computation of ratio of earnings to fixed charges for each of the five years ended December 31, 2008, 2007, 2006, 2005 and 2004.
21.1#	List of Subsidiaries of Duncan Energy Partners L.P.
23.1#	Consent of Deloitte & Touche LLP.
31.1#	Sarbanes-Oxley Section 302 certification of Richard H. Bachmann for Duncan Energy Partners L.P. for the December 31, 2008 annual report on Form 10-K.
31.2#	Sarbanes-Oxley Section 302 certification of W. Randall Fowler for Duncan Energy Partners L.P. for the December 31, 2008 annual report on Form 10-K.
32.1#	Section 1350 certification of Richard H. Bachmann for the December 31, 2008 annual report on Form 10-K.
32.2#	Section 1350 certification of W. Randall Fowler for the December 31, 2008 annual report on Form 10-K.

*	With respect to exhibits incorporated by reference to Exchange Act filings, the Commission file number for Enterprise Products Partners L.P. is 1-14323; Enterprise GP Holdings L.P., 1-32610; and Duncan Energy Partners L.P., 1-33266.
***	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 March 2, 2009.

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

Pursuant to the requirements of the Securities Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated below on March 2, 2009.

Signature	Title (Position with DEP Holdings, LLC)
/s/ Dan L. Duncan Dan L. Duncan	Director and Chairman
/s/ Richard H. Bachmann Richard H. Bachmann	Director, President and Chief Executive Officer
/s/ W. Randall Fowler W. Randall Fowler	Director, Executive Vice President and Chief Financial Officer
/s/ A.J. Teague A.J. Teague	Director, Executive Vice President and Chief Commercial Officer
/s/ Michael A. Creel Michael A. Creel	Director
/s/ Dr. Ralph S. Cunningham Dr. Ralph S. Cunningham	Director
/s/ Larry J. Casey Larry J. Casey	Director
/s/ Joe D. Havens Joe D. Havens	Director
/s/ William A. Bruckmann, III William A. Bruckmann, III	Director
/s/ Michael J. Knesek Michael J. Knesek	Senior Vice President, Controller and Principal Accounting Officer

DUNCAN ENERGY PARTNERS L.P.
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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, 2008 and 2007, and the related consolidated statements of operations and comprehensive income, cash flows, and partners' equity for each of the three years in the period ended December 31, 2008. 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, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008, 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, 2008, 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 2, 2009 expressed 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 2, 2009

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

	December 31, 2008	December 31, 2007*
ASSETS		
Current assets		
Cash and cash equivalents	$ 13,037	$ 2,199
Accounts receivale – trade, net of allowance for doubtful accounts of $45 at December 31, 2008 and $59 at December 31, 2007	117,274	122,309
Gas imbalance receivables, net of allowance for doubtful accounts of $0 at December 31, 2008 and $5,380 at December 31, 2007 (see Note 2)	35,655	34,238
Accounts receivable – related parties	3,257	4,193
Inventories	27,964	21,907
Prepaid and other current assets	4,404	3,063
Total current assets	201,591	187,909
Property, plant and equipment, net	4,330,220	3,738,008
Investments in and advances to Evangeline	4,527	3,490
Intangible assets, net of accumulated amortization of $34,076 at December 31, 2008 and $25,007 at December 31, 2007	52,262	48,583
Goodwill	4,900	4,900
Other assets	1,224	381
Total assets	$ 4,594,724	$ 3,983,271
LIABILITIES AND COMBINED EQUITY		
Current liabilities		
Accounts payable – trade	$ 45,205	$ 36,929
Accounts payable – related parties	48,509	21,712
Accrued product payables	109,683	119,136
Accrued costs and expenses	1,173	2,557
Other current liabilities	48,690	28,786
Total current liabilities	253,260	209,120
Long-term debt (See Note 10)	484,250	200,000
Deferred tax liabilities	5,771	5,507
Other long-term liabilities	7,222	18,710
Parent interest in subsidiaries: (see Note 12)		
DEP I Midstream Businesses	478,368	355,129
DEP II Midstream Businesses	2,613,004	--
Total parent interest in subsidiaries	3,091,372	355,129
Commitments and contingencies		
Partners' equity: (see Note 11)		
Former owner's equity in DEP II Midstream Businesses	--	2,880,137
Limited partners:		
Common units (20,343,100 common units outstanding at December 31, 2008 and 20,301,571 common units outstanding at December 31, 2007)	308,235	317,704
Class B units (37,333,887 Class B units outstanding at December 31, 2008)	453,853	--
General partner	365	557
Accumulated other comprehensive loss	(9,604)	(3,593)
Total partners' equity	752,849	3,194,805
Total liabilities and partners' equity	$ 4,594,724	$ 3,983,271

The accompanying notes are an integral part of these financial statements.
*See Note 1 for information regarding these recasted amounts and basis of financial statement presentation.

DUNCAN ENERGY PARTNERS L.P.
STATEMENTS OF CONSOLIDATED OPERATIONS
AND COMPREHENSIVE INCOME
(Dollars in thousands)

	For the Year Ended December 31,		
	2008	2007*	2006*
Revenues			
Third parties	$ 856,420	$ 759,254	$ 759,020
Related parties	741,648	461,038	504,008
Total revenues (see Note 13)	1,598,068	1,220,292	1,263,028
Costs and expenses			
Operating costs and expenses			
Third parties	1,167,668	1,066,681	1,121,623
Related parties	345,138	104,261	79,249
Total operating costs and expenses	1,512,806	1,170,942	1,200,872
General and administrative costs			
Third parties	3,423	1,701	70
Related parties	14,882	11,415	10,157
Total general and administrative costs	18,305	13,116	10,227
Total costs and expenses	1,531,111	1,184,058	1,211,099
Equity in income of Evangeline	896	182	958
Operating income	67,853	36,416	52,887
Other income (expense)			
Interest expense	(11,965)	(9,279)	--
Interest income	545	638	--
Other, net	(23)	(4)	459
Other income (expense)	(11,443)	(8,645)	459
Income before provision for income taxes, parent interest in subsidiaries and cumulative effect of change in accounting principle	56,410	27,771	53,346
Provision for income taxes	(1,095)	(4,172)	(1,682)
Income before parent interest in income of subsidiaries and the cumulative effect of change in accounting principle	55,315	23,599	51,664
Parent interest in income of subsidiaries: (see Note 12)			
Parent interest – DEP I Midstream Businesses (allocated income)	(11,354)	(19,973)	--
Parent interest – DEP II Midstream Businesses (allocated loss)	3,985	--	--
Total parent interest in income of subsidiaries	(7,369)	(19,973)	--
Income before the cumulative effect of change in accounting principle	47,946	3,626	51,664
Cumulative effect of change in accounting principle (see Note 2)	--	--	18
Net income	$ 47,946	$ 3,626	$ 51,682
Change in fair value of cash flow hedges	(6,011)	(3,593)	--
Comprehensive income	$ 41,935	$ 33	$ 51,682
Net income allocation: (see Note 1)			
Duncan Energy Partners L.P.:			
Limited partners' interest in net income	$ 27,850	$ 18,847	
General partner interest in net income	$ 492	$ 385	
Former owners of DEP II Midstream Businesses	$ 19,604	$ (20,641)	$ (3,655)
Former owners of DEP I Midstream Businesses	n/a	$ 5,035	$ 55,337
Earnings per unit : (see Note 15)			
Basic and diluted income per unit	$ 1.22	$ 0.93	

The accompanying notes are an integral part of these financial statements.
*See Note 1 for information regarding these recasted amounts and
basis of financial statement presentation.

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

	For the Year Ended December 31,		
	2008	2007*	2006*
Operating activities:			
Net income	$ 47,946	$ 3,626	$ 51,682
Adjustments to reconcile net income to net cash flows			
provided by operating activities:			
Depreciation, amortization and accretion	167,836	175,644	156,010
Equity in income of Evangeline	(896)	(182)	(958)
Cumulative effect of change in accounting principle	--	--	(18)
Parent interest in income of subsidiaries	7,369	19,973	--
Gain on sale of assets and related transactions	(543)	(80)	(26)
Deferred income tax expense	292	3,836	1,682
Changes in fair market value of financial instruments	(53)	157	(56)
Net effect of changes in operating accounts (see Note 18)	(1,750)	14,111	(12,672)
Cash flows provided by operating activities	220,201	217,085	195,644
Investing activities:			
Capital expenditures	(759,478)	(340,138)	(213,108)
Contributions in aid of construction costs	9,895	10,067	39,472
Proceeds from sale of assets and related transactions	872	12,609	879
Advances from (to) unconsolidated affiliate	(141)	85	(59)
Cash used for business combinations	(1)	(35,000)	(11,675)
Cash used in investing activities	(748,853)	(352,377)	(184,491)
Financing activities:			
Repayments of debt	(114,653)	(114,000)	--
Borrowings under debt agreements	398,903	314,000	--
Debt issuance costs	(1,635)	(518)	--
Net proceeds from Duncan Energy Partners’ common unit offerings	500	290,466	--
Distributions to Duncan Energy Partners’ unitholders and general partner	(34,388)	(21,834)	--
Distributions to Parent (see Note 11)	(318,103)	(490,989)	--
Contributions from Parent (see Note 11)	183,294	105,035	--
Net cash contributions from former owners of the DEP I Midstream Businesses	--	8,534	44,486
Net cash contributions from (distributions to) former owners of the DEP II Midstream Businesses	425,572	46,794	(55,639)
Cash provided by (used in) financing activities	539,490	137,488	(11,153)
Net changes in cash and cash equivalents	10,838	2,196	--
Cash and cash equivalents, beginning of period	2,199	3	--
Cash and cash Equivalents, end of period	$ 13,037	$ 2,199	$ --

The accompanying notes are an integral part of these financial statements.
*See Note 1 for information regarding these recasted amounts and
basis of financial statement presentation.

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

	Former Owners		Duncan Energy Partners			
	DEP I Midstream Businesses	**DEP II Midstream Businesses**	**Limited Partners**	**General Partner**	**AOCI**	**Total**
Balance, January 1, 2006*	$ 527,767	$ 2,903,568	$ --	$ --	$ --	$ 3,431,335
Net income	55,337	(3,655)	--	--	--	51,682
Non-cash contributions by former owners of DEP I and DEP II Midstream Businesses	98,207	9,573	--	--	--	107,780
Net cash distributions to former owners of DEP I and DEP II Midstream Businesses	44,486	(55,639)	--	--	--	(11,153)
Balance, December 31, 2006*	725,797	2,853,847	--	--	--	3,579,644
Transactions prior to the DEP I dropdown effective February 1, 2007:						
Net income	5,035	(297)	--	--	--	4,738
Non-cash contributions by former owners of DEP I and DEP II Midstream Businesses	6	9	--	--	--	15
Net cash distributions to former owners of DEP I and DEP II Midstream Businesses	8,534	(8,795)	--	--	--	(261)
Balance, January 31, 2007*	739,372	2,844,764	--	--	--	3,584,136
Transactions in connection with Duncan Energy Partners' initial public offering and the DEP I dropdown effective February 1, 2007:						
Adjustment for liabilities of DEP I Midstream Businesses not transferred to Duncan Energy Partners	2,664	--	--	--	--	2,664
Retention by Parent of ownership interests in the DEP I Midstream Businesses	(252,292)	--	--	--	--	(252,292)
Allocation of Parent equity in the DEP I Midstream Businesses to Duncan Energy Partners	(489,744)	--	479,948	9,796	--	--
Net proceeds from Duncan Energy Partners' initial public offering of 14,950,000 common units	--	--	290,466	--	--	290,466
Cash distribution to Parent at time of initial public offering	--	--	(450,360)	(9,191)	--	(459,551)
Balance, February 1, 2007*	$ --	2,844,764	320,054	605	--	3,165,423
Net income		(20,344)	18,847	385	--	(1,112)
Amortization of equity awards		--	201	4	--	205
Non-cash contributions by former owners of DEP II Midstream Businesses		128	--	--	--	128
Cash distributions to partners		--	(21,398)	(437)	--	(21,835)
Net cash distributions to former owner of the DEP II Midstream Businesses		55,589	--	--	--	55,589
Change in fair value of cash flow hedges		--	--	--	(3,593)	(3,593)
Balance, December 31, 2007*		2,880,137	317,704	557	(3,593)	3,194,805
Transactions prior to the DEP II dropdown on December 8, 2008:						
Net income – January 1, 2008 through December 7, 2008		19,604	21,105	431	--	41,140
Amortization of equity awards		--	197	3	--	200
Non-cash contributions by former owners of DEP II Midstream Businesses		194	--	--	--	194
Cash distributions to partners		--	(33,700)	(688)	--	(34,388)
Change in fair value of cash flow hedges		--	--	--	(287)	(287)
Net cash distributions to former owner of the DEP II Midstream Businesses		425,572	--	--	--	425,572
Balance, December 7, 2008		3,325,507	305,306	303	(3,880)	3,627,236
Transactions in connection with the DEP II dropdown on December 8, 2008:						
Retention by Parent of ownership interests in the DEP II Midstream Businesses		(2,595,507)	--	--	--	(2,595,507)
Allocation of Parent equity in the DEP II Midstream Businesses to Duncan Energy Partners		(730,000)	730,000	--	--	--
Cash distribution paid to Parent at DEP II dropdown		--	(280,500)	--	--	(280,500)
Net proceeds from the issuance of 41,529 common units to parent in December 2008		--	500	--	--	500
Balance, December 8, 2008		$ --	755,306	303	(3,880)	751,729
Net income – December 8, 2008 through December 31, 2008			6,746	61	--	6,807
Amortization of equity awards			36	1	--	37
Change in fair value of cash flow hedges			--	--	(5,724)	(5,724)
Balance, December 31, 2008			$ 762,088	$ 365	$ (9,604)	$ 752,849

The accompanying notes are an integral part of these financial statements.
*See Note 1 for information regarding these recasted amounts and
basis of financial statement presentation.

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 thousands of dollars.

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 New York Stock Exchange ("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 ("IPO") of 14,950,000 common units and acquired controlling financial interests in certain midstream energy businesses of Enterprise Products Operating LLC ("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 commonly-controlled affiliates. Duncan Energy Partners is engaged in the business of (i) natural gas liquids ("NGL") transportation and fractionation; (ii) storage of NGL and petrochemical products; (iii) transportation of petrochemical products (iv) the gathering, transportation, storage of natural gas; and (v) the marketing of NGLs and natural gas.

At December 31, 2008, Duncan Energy Partners is owned 99.3% by its limited partners and 0.7% by its general partner, DEP Holdings, LLC ("DEP GP"), which is a wholly owned subsidiary of EPO. At December 31, 2008, EPO owned approximately 74% of Duncan Energy Partner's limited partner interests and 100% of its general partner. DEP GP is responsible for managing the business and operations of Duncan Energy Partners. DEP Operating Partnership L.P. ("DEP OLP"), a wholly owned subsidiary of Duncan Energy Partners, conducts substantially all of Duncan Energy Partners' business. A private company affiliate, EPCO, Inc. ("EPCO"), provides all of Duncan Energy Partners' employees and certain administrative services to the partnership.

Enterprise Products Partners conducts substantially all of its business through EPO, a wholly owned subsidiary. Enterprise Products Partners is a publicly traded partnership, the common units of which are listed on the NYSE under the ticker symbol "EPD." The general partner of Enterprise Products Partners is owned by Enterprise GP Holdings L.P. ("Enterprise GP Holdings"), a publicly traded partnership, the units of which are listed on the NYSE under the ticker symbol "EPE."

One of our principal advantages is our relationship with EPO and EPCO. Our assets connect to various midstream energy assets of EPO and form integral links within EPO's value chain of assets. See Note 14 for additional information regarding our relationship with EPO and EPCO.

The following information summarizes the businesses acquired and consideration we provided in connection with the DEP I and DEP II dropdown transactions.

DEP I Dropdown Transaction

On February 5, 2007, EPO contributed a 66% controlling equity interest in each of the DEP I Midstream Businesses (defined below) to Duncan Energy Partners in a dropdown transaction (the "DEP I dropdown") made in connection with Duncan Energy Partners' IPO. EPO retained the remaining 34% equity interest (as a Parent Interest) in each of the DEP I Midstream Businesses. The DEP I Midstream Businesses consist of (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").

As consideration for the equity interests in the DEP I Midstream Businesses and reimbursement for capital expenditures related to these businesses, Duncan Energy Partners distributed $260.6 million of the $290.5 million of net proceeds from its initial public offering to EPO, plus $198.9 million in borrowings under its initial credit facility (the "DEP I Revolving Credit Facility") and a net 5,351,571 common units. Prior to the DEP I dropdown transaction, we did not have any consolidated indebtedness.

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

§ Mont Belvieu Caverns owns 33 salt dome caverns located in Mont Belvieu, Texas, with an underground NGL and petrochemical 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 gathers, transports, stores and markets natural gas in Louisiana utilizing over 1,000 miles of transmission, lateral and gathering pipelines with an aggregate throughput capacity of one billion cubic feet per day ("Bcf/d"). Acadian Gas also owns a 49.51% equity interest in Evangeline Gas Pipeline Company, L.P. ("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 Duncan Energy Partners' Shoup and Armstrong NGL fractionation plants located in South Texas to Mont Belvieu, Texas. This pipeline commenced operations in January 2007.

DEP II Dropdown Transaction

On December 8, 2008, Duncan Energy Partners entered into a Purchase and Sale Agreement (the "DEP II Purchase Agreement") with EPO and Enterprise GTM Holdings L.P. ("Enterprise GTM," a wholly owned subsidiary of EPO). Pursuant to the DEP II Purchase Agreement, DEP OLP acquired 100% of the membership interests in Enterprise Holding III, LLC ("Enterprise III") from Enterprise GTM, thereby acquiring a 66% general partner interest in Enterprise GC, L.P. ("Enterprise GC"), a 51% general partner interest in Enterprise Intrastate L.P. ("Enterprise Intrastate") and a 51% membership interest in Enterprise Texas Pipeline LLC ("Enterprise Texas"). Collectively, we refer to Enterprise GC, Enterprise Intrastate and Enterprise Texas as the "DEP II Midstream Businesses." As with the DEP I dropdown, EPO was also the sponsor of this second dropdown transaction (the "DEP II dropdown"). Enterprise GTM retained the remaining partner and member interests (as a Parent Interest) in the DEP II Midstream Businesses.

As consideration for the Enterprise III membership interests, EPO received $280.5 million in cash and 37,333,887 Class B limited partner units having, at the time of issuance, a market value of $449.5 million from Duncan Energy Partners. The total value of the consideration provided to EPO and Enterprise GTM was $730.0 million. The cash portion of the consideration provided by Duncan Energy Partners in this dropdown transaction was derived from borrowings under a new bank term loan agreement (the "DEP II Term Loan Agreement") and the proceeds of a $0.5 million equity offering to EPO. On February 9, 2009, the Class B units received a prorated cash distribution of $0.1115 per unit for the distribution that Duncan Energy Partners paid with respect to the fourth quarter of 2008 for the 24-day period from December 8, 2008, the closing date of the DEP II dropdown transaction, to December 31, 2008. On February 1, 2009, the Class B units automatically converted on a one-for-one basis to common units.

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

§ Enterprise GC owns (i) the Shoup and Armstrong NGL fractionation facilities located in South Texas, (ii) a 1,020-mile NGL pipeline system located in South Texas and (iii) 944 miles of natural gas gathering pipelines located in South and West Texas. Enterprise GC's natural gas gathering pipelines include (i) the 272-mile Big Thicket Gathering System located in Southeast Texas, (ii) the 465-mile Waha system located in the Permian Basin of West Texas and (iii) the 207-mile TPC gathering system.

§ 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 6,547-mile Enterprise Texas natural gas pipeline system and leases the Wilson natural gas storage facility. The Enterprise Texas system, along with the Waha, TPC and Channel pipeline systems, comprise the Texas Intrastate System.

Generally, 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 Enterprise III (based on an initial defined investment of $730.0 million) and then to Enterprise GTM (based on an initial defined investment of $452.1 million) in amounts sufficient to generate an aggregate initial annualized return on their respective investments of 11.85%. Distributions in excess of these amounts will be distributed 98% to Enterprise GTM and 2% to Enterprise III. Income and loss of the DEP II Midstream Businesses are first allocated to Enterprise III and Enterprise GTM 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.

See "Parent interest in subsidiaries – DEP II Midstream Businesses" under Note 12 and "Relationship with EPO and EPCO – Company and Limited Partnership Agreements – DEP II Midstream Businesses" under Note 14 for additional information.

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 dropdown 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 dropdown transactions were 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 IPO, or February 5, 2007 (February 1, 2007 for financial accounting and reporting purposes).

References to the "former owners" of the DEP I and DEP II Midstream Businesses primarily refer to the direct and indirect ownership by EPO in these businesses prior to the related dropdown transactions. References to "Duncan Energy Partners" mean the registrant since February 5, 2007 and its consolidated subsidiaries. Generic references to "we," "us" and "our" mean the combined and/or consolidated businesses included in these financial statements for each reporting period.

Our consolidated financial statements include the accounts of Duncan Energy Partners, and prior to the DEP I and DEP II dropdown transactions, the assets, liabilities and operations contributed to us by EPO upon the closing of these dropdown 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 transactions 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, 2006 reflect the combined financial information of the DEP I and DEP II Midstream Businesses on a 100% basis. The results of operations and cash flows for these businesses 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, 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 dropdown 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 dropdown transaction is February 1, 2007. EPO's retained ownership in the DEP I Midstream Businesses (following the dropdown transaction) is presented in our consolidated financial statements as "Parent interest in Subsidiaries – DEP I Midstream Businesses."

- § 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 dropdown transaction. On December 8, 2008, the DEP II Midstream Businesses were contributed to Duncan Energy Partners in the DEP II dropdown 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 dropdown transaction) is presented in our consolidated financial statements as "Parent interest in Subsidiaries – DEP II Midstream Businesses."

Effective with the fourth quarter of 2008, our segment information was restated for all periods in connection with the DEP II dropdown transaction.

As previously noted, the DEP I and DEP II dropdown transactions were accounted for as a reorganization of entities under common control in a manner similar to a pooling of interests. The following information is provided to reconcile total revenues, total segment gross operating margin and net income amounts for the years ended December 31, 2007 and 2006 as currently presented with those we previously presented. There was no change in our reported earnings per unit amounts for either year. See Note 13 for information regarding total segment gross operating margin, which is a non-generally accepted accounting principle ("non-GAAP") financial measure of segment performance.

	For the Year Ended December 31, 2007	For the Year Ended December 31, 2006
	(dollars in millions)	
Total revenues, as previously reported	$ 863.7	$ 924.5
DEP II Midstream Businesses	356.6	338.5
Total revenues, as currently reported	$ 1,220.3	$ 1,263.0
Total segment gross operating margin, as previously reported	$ 86.4	$ 79.8
DEP II Midstream Businesses	138.4	139.3
Total segment gross operating margin, as currently reported	$ 224.8	$ 219.1
Net income, as previously reported	$ 24.2	$ 55.3
Earnings allocated to former owners of DEP II Midstream Businesses	(20.6)	(3.7)
Net income, as currently reported	$ 3.6	$ 51.6

Note 2. Summary of Significant Accounting Policies

Allowance for Doubtful Accounts

Our allowance for doubtful accounts balance is generally 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. As applicable, our allowance also includes estimates for uncollectible natural gas imbalances based on specific identification of accounts.

The following financial statement schedules present changes in our allowance for doubtful account balances associated with accounts receivable – trade and gas imbalance receivables for the periods indicated:

Description	Balance At Beginning Of Period	Additions: Charged To Costs And Expenses	Additions: Charged To Other Accounts	Deductions	Balance At End of Period
Accounts receivable – trade					
Allowance for doubtful accounts					
2008	$ 59	$ --	$ --	$ (14)	$ 45
2007	414	--	--	(355)	59
2006 (1)	3,559	--	--	(3,145)	414

(1) In 2006 we adjusted the allowance account for the receipt of a contingent asset related to a prior business acquisition.

Description	Balance At Beginning Of Period	Additions: Charged To Costs And Expenses	Additions: Charged To Other Accounts	Deductions	Balance At End of Period
Gas imbalance receivables					
Allowance for doubtful accounts					
2008 (1)	$ 5,380	$ --	$ --	$ (5,380)	$ --
2007	5,380	--	--	--	5,380
2006	6,144	--	--	(764)	5,380

(1) Our allowance for estimated uncollectible natural gas imbalances was in place to cover certain charges to producers using our pipelines. In June 2008, settlement agreements were reached with the producers and the reserves were reduced.

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 dropdown transaction dates of February 1, 2007 and December 8, 2008, respectively. For purposes of presentation in our Statements of Consolidated Cash Flows, cash flows provided by (or used in) financing activities during the pre-dropdown 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 Statement of Combined Equity. Conversely, if cash used in investing activities was greater 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 dropdown transaction dates. Following the DEP I and DEP II dropdown transactions, the respective businesses ceased participation in the EPO cash management program and maintain cash balances separately from affiliates.

Consolidation Policy

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. 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.

If an investee 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. Our proportionate share of profits and losses from transactions with our equity method unconsolidated affiliate are eliminated in consolidation and remain on our balance sheet (or those of our equity method investee) in inventory or similar accounts.

To the extent applicable, we would also consolidate other entities and ventures in which we possess a controlling financial interest as well as partnership interests where we are the sole general partner of the partnership. 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.

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, our legal counsel evaluates the perceived merits of legal proceedings that are pending against us and unasserted claims that may result in proceedings, if any, as well as the perceived merits of the amount of relief sought or expected to be sought therein from each.

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 is 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.

Cumulative effect of change in accounting principle

Upon our adoption of Statement of Financial Accounting Standards ("SFAS") 123(R), Share-Based Payment, we recognized, as a benefit, a cumulative effect of a change in accounting principle of $18 thousand based on the SFAS 123(R) requirement to recognize compensation expense based upon the grant date fair value of an equity award and the application of an estimated forfeiture rate to unvested awards. See Note 5 for additional information regarding our accounting for equity awards.

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

In our storage business, we occasionally bill customers in advance of the periods in which we provide storage services. We record such amounts as deferred revenue. We recognize these revenues ratably over the applicable service period. Our deferred revenue was $7.2 million and $4.3 million at December 31, 2008 and 2007, respectively.

Earnings per Unit

See Note 15 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. Ongoing environmental compliance costs are charged to expense as incurred. Expenditures to mitigate or prevent future environmental contamination are capitalized. 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, 2008, none of our estimated environmental remediation liabilities are discounted to present value since the ultimate amount and timing of cash payments for such liabilities are not readily determinable. Our operations include activities that are subject to federal and state environmental regulations. Expenses for environmental compliance and monitoring were $0.2 million, $1.0 million, and $1.0 million for the years ended December 31, 2008, 2007 and 2006, respectively.

At December 31, 2008, our reserve for environmental remediation projects totaled $0.6 million. Under the terms of the Omnibus Agreement (see Note 14), a $6.3 million reserve for environmental remediation projects related to the use of mercury gas meters was retained by EPO at the time of the DEP II dropdown transaction. The retention of this liability is reflected in the following table as a deduction in the overall reserve balance during 2008.

Description	Balance At Beginning Of Period	Additions: Charged To Costs And Expenses	Additions: Charged To Other Accounts	Deductions	Balance At End of Period
Other current liabilities					
Reserve for environmental liabilities					
2008	$ 17,769	$ 315	$ 186	$ (17,666)	$ 604
2007	20,680	256	25	(3,192)	17,769
2006	21,197	250	--	(767)	20,680

The $17.7 million deduction 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 dropdown 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 long-term incentive plans involving equity awards.

Estimates

Preparing our financial statements in conformity with GAAP requires management to make estimates and assumptions that affect reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and 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 and Financial Instruments

Due to their short-term nature, accounts receivable, accounts payable and accrued expenses are carried at amounts which reasonably approximate their fair values. The fair values associated with our commodity financial instruments were developed using available market information and appropriate valuation techniques.

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

	December 31, 2008		December 31, 2007	
Financial Instruments	Carrying Value	Fair Value	Carrying Value	Fair Value
Financial assets:				
Accounts receivable	$ 156,186	$ 156,186	$ 160,740	$ 160,740
Commodity financial instruments (1)	1,897	1,897	212	212
Financial liabilities:				
Accounts payable and accrued expenses	$ 204,570	$ 204,570	$ 180,334	$ 180,334
Commodity financial instruments (1)	1,981	1,981	180	180
Variable-rate revolving credit facility	202,000	202,000	200,000	200,000
Variable-rate term loan	282,250	282,250	--	--
Interest rate swaps	9,769	9,769	3,782	3,782

(1) Represents commodity financial instrument transactions that have either (i) not settled or (ii) settled and not been invoiced. Settled and invoiced transactions are reflected in either accounts receivable or accounts payable depending on the outcome of the transaction.

We are exposed to financial market risks, including changes in commodity prices and interest rates. We may use financial instruments (i.e. futures, forwards, swaps, options and other financial instruments with similar characteristics) to mitigate the risks of certain identifiable and anticipated transactions. See Note 6 for more information regarding our financial instruments.

Impairment Testing for Goodwill

Our goodwill amounts are assessed for impairment (i) on a routine annual basis 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 implied fair value. We have not recognized any impairment losses related to goodwill for any of the periods presented. See Note 9 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 in accordance with SFAS 144. 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 carrying value of a long-lived asset exceeds the sum of its undiscounted cash flows, a non-cash asset impairment charge is recognized equal to the excess of the asset's carrying value over its estimated fair value. Fair value is defined as the estimated amount at which an asset or liability could be bought or settled, respectively, in an arm's-length transaction. We measure fair value using market prices or, in the absence of such data, appropriate valuation techniques. We had no such impairment charges during the periods presented.

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 a history of investee operating losses or long-term adverse changes in the investee's industry. If we determine that a loss in the investment's value is attributable to an event other than temporary decline, we adjust the carrying value of the investment to its fair value through a charge to earnings. We had no such impairment charges during the periods presented.

Inventories

Our inventory consists of natural gas volumes that (i) are available-for-sale and (ii) used for operational system balancing. At December 31, 2008 and 2007, the total value of our natural gas inventory was $28.0 million and $21.9 million, respectively.

Our available-for-sale inventory is valued at the lower of average cost or market. The capitalized cost of our available-for-sale inventory includes shipping and handling charges that are directly related to volumes we purchase from third parties. As volumes are sold and delivered out of our available-for-sale inventory, the average cost of such inventory is charged to cost of sales, which is a component of operating costs and expenses. Transportation and handling fees associated with products we sell and deliver to customers are charged to operating costs and expenses as incurred. At December 31, 2008 and 2007, the value of our available-for-sale natural gas inventory was $9.7 million and $7.1 million, respectively.

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, 2008 and 2007, the value of natural gas held in inventory for operational system balancing was $15.5 million and $10.3 million, respectively.

As a result of fluctuating market conditions, we occasionally recognize lower of average cost or market ("LCM") adjustments when the historical cost of our available-for-sale inventory exceeds its net realizable value. These non-cash adjustments are recorded as a component of cost of sales within operating costs and expenses. We recognized LCM adjustments of $1.8 million and $0.3 million for the years ended December 31, 2008 and 2007, respectively. No adjustments were required for the year ended December 31, 2006.

Operating costs and expenses, as presented on our Statements of Consolidated Operations and Comprehensive Income, includes cost of sales amounts related to the sale of inventory. Our cost of sales amounts were $1.06 billion, $765.1 million and $833.5 million for the years ended December 31, 2008, 2007 and 2006, respectively.

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 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 on-going 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 is representative of the estimated value of the imbalances upon final settlement. Changes in natural gas prices may impact our estimates.

At December 31, 2008 and 2007, our imbalance receivables were $35.7 million and $34.2 million, respectively. At December 31, 2008 and 2007, our imbalance payables were $43.6 million and $37.3 million, respectively. Imbalance payables are reflected as a component of "Accrued products payables" on our Consolidated Balance Sheets.

Parent Interest in Subsidiaries

See Note 12 for information regarding EPO's parent interest in the DEP I and DEP II Midstream Businesses.

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 basins (based on proved reserves at the time of the analysis) from which such assets derive their throughput or processing 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, the following: (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. See Note 7 for additional information regarding our property, plant and equipment, including a change in depreciation expense beginning January 1, 2008 resulting from a change in the estimated useful life of certain assets.

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 7 for additional information regarding our property, plant and equipment.

Provision for Income Taxes

Provision for income taxes is primarily applicable to our state tax obligations under the Revised Texas Franchise Tax. In general, legal entities that conduct business in Texas are subject to the Revised Texas Franchise Tax. In May 2006, the State of Texas expanded its then existing franchise tax to include limited partnerships, limited liability companies, corporations and limited liability partnerships. As a result of the change in tax law, our tax status in the State of Texas has changed from non-taxable to taxable.

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.

In accordance with Financial Accounting Standards Board Interpretation (“FIN”) 48, “Accounting for Uncertainty in Income Taxes,” we must 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 FIN 48.

Revenue Recognition

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 accounting guidance that will affect our future financial statements: SFAS 141(R), Business Combinations; FASB Staff Position (“FSP”) SFAS 142-3, Determination of the Useful Life of Intangible Assets; SFAS 157, Fair Value Measurements; SFAS 160, Noncontrolling Interests in Consolidated Financial Statements – An amendment of ARB 51; SFAS 161, Disclosures about Derivative Instruments and Hedging Activities – An Amendment of SFAS 133; and Emerging Issues Task Force (“EITF”) 08-6, Equity Method Investment Accounting Considerations.

SFAS 141(R), Business Combinations. SFAS 141(R) replaces SFAS 141, “Business Combinations” and was effective January 1, 2009. SFAS 141(R) retains the fundamental requirements of SFAS 141 in that the acquisition method of accounting (previously termed the “purchase method”) be used for all business combinations and for the “acquirer” to be identified in each business combination. SFAS 141(R) defines the acquirer as the entity that obtains control of one or more businesses in a business combination and establishes the acquisition date as the date that the acquirer achieves control. This new guidance also retains guidance in SFAS 141 for identifying and recognizing intangible assets separately from goodwill. SFAS 141(R) will have an impact on the way in which we evaluate acquisitions.

The objective of SFAS 141(R) is to improve the relevance, representational faithfulness, and comparability of the information a reporting entity provides in its financial reports about business combinations and their effects. To accomplish this, SFAS 141(R) establishes principles and requirements for how the acquirer:

- § Recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, and any noncontrolling interests in the acquiree.

- § Recognizes and measures any goodwill acquired in the business combination or a gain resulting from a bargain purchase. SFAS 141(R) defines a bargain purchase as a business combination in which the total acquisition-date fair value of the identifiable net assets acquired exceeds the fair value of the consideration transferred plus any noncontrolling interest in the acquiree, and requires the acquirer to recognize that excess in net income as a gain attributable to the acquirer.

- § Determines what information to disclose to enable users of the financial statements to evaluate the nature and financial effects of the business combination.

SFAS 141(R) also requires that direct costs of an acquisition (e.g. finder's fees, outside consultants, etc.) be expensed as incurred and not capitalized as part of the purchase price.

FSP FAS 142-3, Determination of the Useful Life of Intangible Assets. In April 2008, the Financial Accounting Standards Board ("FASB") issued FSP 142-3, which revised the factors that should be considered in developing renewal or extension assumptions used in determining the useful life of recognized intangible assets under SFAS 142, Goodwill and Other Intangible Assets. These revisions are intended to improve consistency between the useful life of a recognized intangible asset under SFAS 142 and the period of expected cash flows used to measure the fair value of such assets under SFAS 141(R) and other accounting guidance. The measurement and disclosure requirements of this new guidance will be applied to intangible assets acquired after January 1, 2009. Our adoption of this guidance is not expected to have a material impact on our consolidated financial statements.

SFAS 157, Fair Value Measurements. SFAS 157 defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. Although certain provisions of SFAS 157 were effective January 1, 2008, the remaining guidance of this new standard applicable to nonfinancial assets and liabilities was effective January 1, 2009. See Note 6 for information regarding fair value-related disclosures required for 2008 in connection with SFAS 157.

SFAS 157 applies to fair-value measurements that are already required (or permitted) by other accounting standards and is expected to increase the consistency of those measurements. SFAS 157 emphasizes that fair value is a market-based measurement that should be determined based on the assumptions that market participants would use in pricing an asset or liability. Companies are required to disclose the extent to which fair value is used to measure assets and liabilities, the inputs used to develop such measurements, and the effect of certain of the measurements on earnings (or changes in net assets) during a period. Our adoption of this guidance is not expected to have a material impact on our consolidated financial statements. SFAS 157 will impact the valuation of assets and liabilities (and related disclosures) in connection with future business combinations and impairment testing.

SFAS 160, Noncontrolling Interests in Consolidated Financial Statements – an amendment of ARB 51. SFAS 160 established accounting and reporting standards for noncontrolling interests, which have been referred to as minority interests in prior accounting literature. SFAS 160 was effective January 1, 2009. A noncontrolling interest is that portion of equity in a consolidated subsidiary not attributable, directly or indirectly, to a reporting entity. This new standard requires, among other things, that (i) ownership interests of noncontrolling interests be presented as a component of equity on the balance sheet (i.e., elimination of the "mezzanine" presentation); (ii) elimination of minority interest expense as a line item on the statement of income and, as a result, that net income be allocated between the reporting entity and noncontrolling interests on the face of the statement of income; and (iii) enhanced disclosures regarding noncontrolling interests.

SFAS 160 will affect the presentation of Parent interest on our financial statements beginning with the first quarter of 2009. Parent interest in the net assets of the DEP I and DEP II Midstream Businesses will be presented as a component of partners' equity on our consolidated balance sheets. With respect to our consolidated statements of operations, net income and comprehensive income will be allocated between

Parent interest, us and any former owners (as applicable). We will continue to provide detailed footnote disclosures regarding the Parent interest amounts, including related reconciliations.

SFAS 161, Disclosures about Derivative Instruments and Hedging Activities - An Amendment of SFAS 133. SFAS 161 revised the disclosure requirements for financial instruments and related hedging activities to provide users of financial statements with an enhanced understanding of (i) why and how an entity uses financial instruments, (ii) how an entity accounts for financial instruments and related hedged items under SFAS 133, Accounting for Derivative Instruments and Hedging Activities (including related interpretations), and (iii) how financial instruments and related hedged items affect an entity's financial position, financial performance, and cash flows.

SFAS 161 requires qualitative disclosures about objectives and strategies for using financial instruments, quantitative disclosures about fair value amounts of and gains and losses on financial instruments, and disclosures about credit risk-related contingent features in financial instrument agreements. SFAS 161 was effective January 1, 2009 and we will apply its requirements beginning with the first quarter of 2009.

EITF 08-6, Equity Method Investment Accounting Considerations. EITF 08-6 clarifies the accounting for certain transactions and impairment considerations involving equity method investments under SFAS 141(R) and SFAS 160. EITF 08-6 generally requires that (i) transaction costs should be included in the initial carrying value of an equity method investment; (ii) an equity method investor shall not test separately an investee's underlying assets for impairment, rather such testing should be performed in accordance with Opinion 18 (i.e., on the equity method investment itself); (iii) an equity method investor shall account for a share issuance by an investee as if the investor had sold a proportionate share of its investment (any gain or loss to the investor resulting from the investee's share issuance shall be recognized in earnings); and (iv) a gain or loss should not be recognized when changing the method of accounting for an investment from the equity method to the cost method. EITF 08-6 was effective January 1, 2009.

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 business segment generates revenues primarily from the provision of natural gas pipeline transportation and gathering services, natural gas storage services and from the sale of natural gas. Our natural gas pipeline systems generate revenues from transportation and gathering agreements as customers are billed a fee per unit of volume multiplied by the volume delivered or gathered (typically in MMBtus). Fees charged under these arrangements are either contractual or regulated by governmental agencies. Revenues associated with these fee-based contracts are recognized when volumes have been delivered. The Texas Intrastate System also earns capacity reservations fees when shippers elect to reserve capacity in our pipelines. Revenues from capacity reservation fees are recognized ratably during the period the customer reserves capacity.

In addition to fee-based gathering arrangements, certain gathering pipelines within our Texas Intrastate System provide aggregating and bundling services, in which we purchase and resell natural gas for certain producers. Under these arrangements, we purchase natural gas at the wellhead from a producer based on an index price less a pricing differential and resell the natural gas at a pipeline interconnect to another customer based on the same index price. The intent of such arrangements is to earn a fee (based on the differential in prices) for providing gathering services to producers. Revenues associated with aggregating and bundling services are recognized when natural gas volumes have been delivered.

In certain cases, we take title to small volumes of condensate that accumulate in our natural gas pipelines. We sell these volumes at market-based prices and recognize the revenues when the condensate is delivered.

We also have natural gas sales contracts associated with Acadian Gas whereby revenue is recognized when we sell and deliver a volume of natural gas to customers. Revenues from these sales contracts are based upon market-related prices as determined by the individual agreements.

Revenues from firm natural gas storage contracts typically have two components: (i) a monthly demand payment, which is associated with storage capacity reservations, and (ii) a fuel-based fee per unit of volume injected at each location. 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.

NGL Pipelines & Services

A portion of segment revenues are derived from the sale of NGLs obtained through processing arrangements associated with our Big Thicket Gathering System. Under percent-of-proceeds contracts, we extract mixed NGLs from the producers' natural gas stream and recognize revenue when the extracted NGLs are delivered and sold, often to EPO. In turn, we pay the producers for their percentage share of such NGL sales proceeds. Under wellhead purchase contracts, we acquire a producer's natural gas stream at the point of production (i.e., the wellhead), process such natural gas to remove NGLs, and recognize revenue when the extracted NGLs and residue natural gas are delivered and sold, often to affiliates of EPO.

Our NGL pipelines generate transportation revenues based on a fixed fee per gallon of liquids transported (corresponding to the terms of each contractual arrangement) multiplied by the volume delivered (typically in MBPD). Revenue is generally recognized when volumes have been delivered to customers. Our pipeline transportation arrangements may also include a service bundle in which we charge customers a fee for NGL and related product storage.

We collect storage revenues under our NGL and petrochemical 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 production of polyvinyl chloride ("PVC").

We enter into fee-based arrangements and percent-of-proceeds contracts for the NGL fractionation services we provide to customers. Under the fee-based arrangements, revenue is recognized in the period services are provided. These fee-based arrangements typically include a contractually stated base-fractionation fee (typically in cents per gallon) that is subject to adjustment for changes in certain fractionation expenses (e.g., plant fuel costs). Under percent-of-proceeds arrangements, we extract the mixed NGLs from the producer's natural gas stream and recognize revenue when the extracted NGLs are delivered and sold to EPO.

Petrochemical Services

Revenues recorded for the Lou-Tex Propylene Pipeline and Sabine Propylene Pipeline are primarily based on exchange agreements with Shell 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.

For those periods prior to February 1, 2007, EPO was the shipper of record on these pipeline systems and billed Shell and Exxon Mobil for actual amounts due under the exchange agreements. In turn, Lou-Tex Propylene and Sabine Propylene billed EPO the full tariff rate, which was in excess of the amounts EPO billed Shell and Exxon Mobil under the exchange agreements. Effective February 1, 2007, EPO assigned the exchange agreements to us and Lou-Tex Propylene and Sabine Propylene started billing Shell and Exxon Mobil for amounts due under the exchange agreements.

Note 5. Accounting for Equity Awards

We account for equity awards in accordance with SFAS 123(R), Share-Based Payment. Such awards were not material to our consolidated financial position, results of operation, and cash flows for all periods presented. The amount of equity-based compensation allocable to the Company's businesses was $0.9 million, $0.5 million and $0.2 million for the years ended December 31, 2008, 2007 and 2006.

SFAS 123(R) requires us to recognize compensation expense related to equity awards based on the fair value of the award at grant date. We do not directly employ any of the persons responsible for the management and operations of our businesses. These functions were performed by employees of EPCO pursuant to an administrative services agreement (see Note 14). Certain key employees of EPCO participate in long-term incentive compensation plans managed by EPCO. The compensation expense we record related to unit-based awards is based on an allocation of the total cost of such incentive plans to EPCO. We record our pro rata share of such costs based on the percentage of time each employee spends on our consolidated business activities.

EPCO 1998 Plan

The EPCO 1998 Plan provides for incentive awards to EPCO's key employees who perform management, administrative or operational functions for us or our affiliates. Awards granted under the EPCO 1998 Plan may be in the form of unit options, restricted units, phantom units and distribution equivalent rights ("DERs"). As used in the context of the EPCO plans, the term "restricted unit" represents a time-vested unit under SFAS 123(R). Such awards are non-vested until the required service period expires.

Under the EPCO 1998 Plan, non-qualified incentive options to purchase a fixed number of Enterprise Products Partners' common units may be granted to key employees of EPCO who perform management, administrative or operational functions for us. When issued, the exercise price of each option grant is equivalent to the market price of the underlying equity on the date of grant. During 2008, in response to changes in the federal tax code applicable to certain types of equity awards, EPCO amended the terms of certain of unit options outstanding under the EPCO 1998 Plan. In general, the expiration dates of these awards were modified from May and August 2017 to December 2012.

Restricted unit awards under the EPCO 1998 Plan allow recipients to acquire common units of Enterprise Products Partners (at no cost to the recipient) once a defined vesting period expires, subject to certain 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 Enterprise Products Partners' common units on the date of grant less an allowance for estimated forfeitures. Each recipient is also entitled to cash distributions equal to the product of the number of restricted units outstanding for the participant and the cash distribution per unit paid by Enterprise Products Partners to its unitholders. In 2008, a total of 766,200 restricted units were issued to key employees of EPCO, including 101,500 restricted units issued to our most highly compensated executive officers. The aggregate grant date fair value of restricted units awards issued in 2008 was $19.1 million based on a grant date market price of Enterprise Products Partners' common units ranging from $25.00 to $32.31 per unit and an estimated forfeiture rate of 17.0%.

The EPCO 1998 Plan also provides for the issuance of phantom unit awards, including related DERs. No phantom unit awards or associated DERs have been granted under the EPCO 1998 Plan.

At December 31, 2008, there was an estimated $1.7 million and $31.5 million of total unrecognized compensation cost related to nonvested unit option awards and restricted unit awards, respectively, granted under the EPCO 1998 Plan. We expect to recognize our share of these costs over a weighted-average period of 2.1 years (for unit options) and 2.3 years (for restricted units).

EPD 2008 LTIP

The EPD 2008 LTIP provides for incentive awards to EPCO's key employees who perform management, administrative or operational functions for us or our affiliates. Awards granted under the EPD 2008 LTIP may be in the form of unit options, restricted units, phantom units and DERs.

When issued, the exercise price of each option grant was equivalent to the market price per unit of Enterprise Products Partners' common units on the date of grant. In general, options granted under the EPD 2008 LTIP have a vesting period of four years and are exercisable during specified periods with the calendar year immediately following the year in which vesting occurs. At December 31, 2008, no restricted units, phantom units or DERs had been issued under this plan.

In May 2008, a total of 795,000 unit options were granted to key employees of EPCO, including 240,000 unit options granted to our most highly compensated executive officers. The grant date fair values of unit options granted in May 2008 were 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) risk-free interest rate of 3.3%; (iv) expected distribution yield on Enterprise Products Partners' common units of 7.0%; (v) expected unit price volatility on Enterprise Products Partners' common units of 19.8%; and (vi) an estimated forfeiture rate of 17.0%.

At December 31, 2008, there was an estimated $1.3 million of total unrecognized compensation cost related to nonvested unit options granted under the EPD 2008 LTIP. We expect to recognize our share of this cost over a remaining period of 3.4 years.

Employee Partnerships

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 five limited partnerships. The employees were issued Class B limited partner interests and admitted as Class B limited partners in the Employee Partnerships without capital contributions. The Employee Partnerships are: EPE Unit I, 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"). Enterprise Unit L.P. ("Enterprise Unit") and EPCO Unit L.P. ("EPCO Unit") were formed in 2008. We will recognize our share of costs in accordance with the ASA.

Each Employee Partnership has a single Class A limited partner, which is a private company affiliate 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 ("Capital Base") in the Employee Partnership and any residual quarterly cash amounts, if any, are distributed to the Class B limited partners. Upon liquidation, Employee Partnership 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.

The Class B limited partner interests entitle each holder to participate in the appreciation in value of the publicly traded limited partner units owned by the underlying Employee Partnership. The Employee Partnerships own either Enterprise GP Holdings units ("EPE units") or Enterprise Products Partners' common units ("EPD units") or both. The Class B limited partner interests are subject to forfeiture if the participating employee's employment with EPCO is terminated prior to vesting, with customary exceptions for death, disability and certain retirements. The risk of forfeiture will also lapse upon certain change in control events.

The following table summarizes key elements of each Employee Partnership as of December 31, 2008:

Employee Partnership	Description of Assets	Initial Class A Capital Base	Class A Partner Preferred Return	Award Vesting Date (1)	Grant Date Fair Value of Awards (2)	Unrecognized Compensation Cost (3)
EPE Unit I	1,821,428 EPE units	$51.0 million	4.50% to 5.725% (4)	November 2012	$17.0 million	$9.3 million
EPE Unit II	40,725 EPE units	$1.5 million	4.50% to 5.725% (4)	February 2014	$0.3 million	$0.2 million
EPE Unit III	4,421,326 EPE units	$170.0 million	3.80%	May 2014	$32.7 million	$25.1 million
Enterprise Unit	881,836 EPE units 844,552 EPD units	$51.5 million	5.00%	February 2014	$4.2 million	$3.7 million
EPCO Unit	779,102 EPD units	$17.0 million	4.87%	November 2013	$7.2 million	$7.0 million

(1) The vesting date corresponds to the termination date for each Employee Partnership. The termination date may be accelerated for change of control and other events as described in the underlying partnership agreements.

(2) The estimated grant date fair values were determined using a Black-Scholes option pricing model and reflect adjustments for forfeitures, regrants and other modifications. See following table for information regarding the fair value assumptions.

(3) Unrecognized compensation cost represents the total future expense to be recognized by the EPCO group of companies as of December 31, 2008. We will recognize our allocated share of such costs in the future. The period over which the unrecognized compensation cost will be recognized is as follows for each Employee Partnership: 3.9 years, EPE Unit I; 5.1 years, EPE Unit II; 5.4 years, EPE Unit III; 5.1 years, Enterprise Unit; and 4.9 years, EPCO Unit.

(4) In July 2008, the Class A preferred return was reduced from 6.25% to the floating amounts presented.

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

Employee Partnership	Expected Life of Award	Risk-Free Interest Rate	Expected Distribution Yield of EPE/EPD units	Expected Unit Price Volatility of EPE/EPD units
EPE Unit I	3 to 5 years	2.7% to 5.0%	3.0% to 4.8%	16.6% to 30.0%
EPE Unit II	5 to 6 years	3.3% to 4.4%	3.8% to 4.8%	18.7% to 19.4%
EPE Unit III	4 to 6 years	3.2% to 4.9%	4.0% to 4.8%	16.6% to 19.4%
Enterprise Unit	6 years	2.7% to 3.9%	4.5% to 8.0%	15.3% to 22.1%
EPCO Unit	5 years	2.4%	11.1%	50.0%

Note 6. Financial Instruments

We are exposed to financial market risks, including changes in commodity prices and interest rates. We may use financial instruments (i.e. futures, forwards, swaps, options and other financial instruments with similar characteristics) to mitigate the risks of certain identifiable and anticipated transactions.

Interest Rate Risk Hedging Program

As presented in the following table, we had three interest rate swap agreements outstanding at December 31, 2008 that were accounted for as cash flow hedges.

Hedged Variable Rate Debt	**Number of Swaps**	**Period Covered by Swap**	**Termination Date of Swap**	**Variable to Fixed Rate** (1)	**Notional Value**
Duncan Energy Partners' Revolver, due Feb. 2011	3	Sep. 2007 to Sep. 2010	Sep. 2010	1.47% to 4.62%	$175.0 million

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

In September 2007, we executed three floating-to-fixed interest rate swaps having a combined notional value of $175 million. The purpose of entering into these transactions was to reduce the sensitivity of our earnings to changes in variable interest rates charged under the DEP I Revolving Credit Facility. We recognized a loss in interest expense of $2.0 million and a benefit of $0.2 million from these swaps during the years ended December 31, 2008 and 2007, respectively, which includes a nominal amount of ineffectiveness. In 2009, we expect to reclassify $6.0 million of accumulated other comprehensive loss that was generated by these interest rate swaps as an increase to interest expense.

The aggregate fair value of these interest rate swaps was a liability of $9.8 million and a liability of $3.8 million for the years ended December 31, 2008 and 2007, respectively. As cash flow hedges, any increase or decrease in fair value (to the extent such financial instruments are effective hedges) would be recorded in other comprehensive income and amortized into income over the settlement period hedged. Any hedge ineffectiveness is recorded directly into earnings as an increase in interest expense.

Commodity Risk Hedging Program

In addition to its natural gas transportation business, Acadian Gas engages in the purchase and sale of natural gas to third party customers in the Louisiana area. The price of natural gas fluctuates in response to changes in supply, market uncertainty, and a variety of additional factors that are beyond our control. We may use commodity-based financial instruments such as futures, swaps and forward contracts to mitigate such risks. In general, the types of risks we attempt to hedge are those related to the variability of future earnings and cash flows resulting from changes in commodity prices. The financial instruments we utilize may be settled in cash or with another financial instrument.

Acadian Gas also enters into a small number of cash flow hedges in connection with its purchase of natural gas held-for-sale to third parties. In addition, Acadian Gas enters into a limited number of offsetting mark-to-market financial instruments that effectively fix the price of natural gas for certain of its customers.

Historically, the use of commodity financial instruments by Acadian Gas was governed by policies established by the general partner of Enterprise Products Partners. Our general partner now monitors the hedging strategies associated with the physical and financial risks of Acadian Gas, 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.

The fair value of the Acadian Gas commodity financial instrument portfolio was a negligible amount at both December 31, 2008 and 2007. We recorded losses of $1.1 million and $0.8 million for the years ended December 31, 2007 and 2006, respectively, and a nominal loss for the year ended December 31, 2008.

Adoption of SFAS 157 - Fair Value Measurements

On January 1, 2008, we adopted the provisions of SFAS 157 that apply to financial assets and liabilities. We adopted the provisions of SFAS 157 that apply to nonfinancial assets and liabilities on

January 1, 2009 (see Note 3). SFAS 157 defines fair value 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. These assumptions include 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.

SFAS 157 established a three-tier hierarchy 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 SFAS 157 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 in sufficient frequency so as to provide pricing information on an ongoing basis (e.g., the NYSE or the New York Mercantile Exchange). Level 1 primarily consists of financial assets and liabilities such as exchange-traded financial instruments, publicly-traded equity securities and U.S. government treasury securities.

§ 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, time value of money, volatility factors for stocks, and current market and contractual prices for the underlying instruments, as well as 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 rates and yield curves at commonly quoted intervals). Level 2 includes non-exchange-traded instruments such as over-the-counter forward contracts, options and repurchase agreements.

§ 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 inputs 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. We had no Level 3 financial assets or liabilities at December 31, 2008.

The following table sets forth, by level within the fair value hierarchy, our financial assets and liabilities measured on a recurring basis at December 31, 2008. 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 and their placement within the fair value hierarchy levels.

	Level 1	Level 2	Level 3	Total
Financial assets:				
Commodity financial instruments	$ 37	$ 1,860	$ --	$ 1,897
Financial liabilities:				
Commodity financial instruments	$ 1,863	$ 118	$ --	$ 1,981
Interest rate financial instruments	--	9,799	--	9,799
Total financial liabilities	$ 1,863	$ 9,917	$ --	$ 11,780

Note 7. 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, 2008	At December 31, 2007
Plant and pipeline facilities (1)	3-40 (4)	$ 4,174,968	$ 3,657,651
Underground storage wells and related assets (2)	5-35 (5)	407,945	386,744
Transportation equipment (3)	3-10	10,303	8,227
Land		23,922	17,656
Construction in progress		458,962	257,246
Total		5,076,100	4,327,524
Less accumulated depreciation		745,880	589,516
Property, plant and equipment, net		$ 4,330,220	$ 3,738,008

(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, 18-40 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).

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, most notably the assets that constitute our Texas Intrastate System as of January 1, 2008. These revisions extend 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 income from continuing operations (before Parent interest) by equal amounts from what they would have been absent the change. Depreciation expense for the years ended December 31, 2008, 2007 and 2006 was $158.5 million, $163.4 million and $148.2 million, respectively.

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, 2006.

ARO liability balance, December 31, 2006	$	2,287
Liabilities incurred		32
Liabilities settled		(732)
Accretion expense		263
Revisions in estimated cash flows		6,207
ARO liability balance, December 31, 2007	$	8,057
Liabilities incurred		1,315
Liabilities settled		(5,310)
Accretion expense		301
Revisions in estimated cash flows		253
ARO liability balance, December 31, 2008	$	4,616

Based on information currently available, we estimate that annual accretion expense will be approximately $0.3 million, $0.3 million, $0.3 million, $0.4 million and $0.4 million for the years 2009 through 2013, respectively.

Note 8. Investments in and Advances to Unconsolidated Affiliate - 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 Evangeline Gas Pipeline, L.P. (“EGP”) and a 45.05% direct interest in Evangeline Gas Corp. (“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.

At December 31, 2008 and 2007, the carrying value of our investment in Evangeline was $4.5 million and $3.5 million, respectively. Our Statements of Consolidated Operations and Comprehensive Income reflects equity earnings from Evangeline of $0.9 million, $0.2 million and $1.0 million for the years ended December 31, 2008, 2007 and 2006, respectively. 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. Quantities delivered to Entergy totaled 36.9 BBtus for the year ended December 31, 2008 and 36.8 BBtus for each of the years ended December 31, 2007 and 2006, respectively. The sales contract contains provisions whereby Entergy is obligated to pay Evangeline a minimum fee each period of approximately $6.5 million, whether or not it is able to take delivery of natural gas volumes.

In connection with the Entergy sales contract, Evangeline has entered into a natural gas purchase contract with 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. Due to this pricing methodology, Evangeline’s monthly net sales margin under the Entergy gas sales contract is essentially fixed.

Entergy has the option to purchase the Evangeline pipeline system or an equity interest in Evangeline. 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.

Summarized financial information of Evangeline is presented below.

	At December 31, 2008	At December 31, 2007
BALANCE SHEET DATA:		
Current assets	$ 33,534	$ 28,566
Property, plant and equipment, net	4,204	5,174
Other assets	17,483	21,185
Total assets	$ 55,221	$ 54,925
Current liabilities	$ 24,177	$ 21,406
Other liabilities	20,445	24,738
Consolidated equity	10,599	8,781
Total liabilities and consolidated equity	$ 55,221	$ 54,925

	For the Year Ended December 31, 2008	2007	2006
INCOME STATEMENT DATA:			
Revenues	$ 371,765	$ 272,931	$ 287,275
Operating income	7,242	6,337	7,939
Net income	1,818	371	1,964

Note 9. Intangible Assets and Goodwill

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

	At December 31, 2008			At December 31, 2007		
	Gross Value	Accum. Amort.	Carrying Value	Gross Value	Accum. Amort.	Carrying Value
NGL Pipelines & Services:						
Mont Belvieu storage contracts	$ 8,127	$ (1,626)	$ 6,501	$ 8,127	$ (1,393)	$ 6,734
Markham NGL storage contracts	32,664	(18,509)	14,155	32,664	(14,154)	18,510
South Texas NGL business customer relationships	11,808	(4,270)	7,538	11,808	(3,406)	8,402
San Felipe gathering customer relationships	12,747	(2,079)	10,668	--	--	--
Segment total	65,346	(26,484)	38,862	52,599	(18,953)	33,646
Natural Gas Pipelines & Services:						
Texas Intrastate System customer relationships	20,992	(7,592)	13,400	20,992	(6,055)	14,937
Total all segments	$ 86,338	$ (34,076)	$ 52,262	$ 73,591	$ (25,008)	$ 48,583

Due to the renewable nature of the underlying contracts, we amortize the Mont Belvieu storage contracts on a straight-line basis over the estimated 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 using the straight-line method over the remaining terms of the underlying agreements.

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,		
	2008	2007	2006
NGL Pipelines & Services	$ 7,531	$ 5,531	$ 5,621
Natural Gas Pipelines & Services	1,537	1,680	1,837
Total segments	$ 9,068	$ 7,211	$ 7,458

Based on information currently available, the following table presents an estimate of future amortization expense associated with our intangible assets at December 31, 2008:

	For the Year Ended December 31,				
	2009	2010	2011	2012	2013
NGL Pipelines & Services	$ 7,015	$ 6,716	$ 6,454	$ 2,960	$ 1,674
Natural Gas Pipelines & Services	1,406	1,286	1,177	1,077	985
Total segments	$ 8,421	$ 8,002	$ 7,631	$ 4,037	$ 2,659

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. Our goodwill at December 31, 2008 and 2007 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 goodwill recorded in connection with this merger can be attributed to Enterprise Products Partners' belief (at the time the merger was consummated) that the merged partnerships would benefit from the strategic location of each partnership's assets and the industry relationships that each possessed. In addition, Enterprise Products Partners expected that various operating synergies could develop (such as reduced general and administrative costs and interest savings) that would result in improved financial results for the merged entity.

Note 10. Debt Obligations

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

	At December 31,	
	2008	2007
DEP I Revolving Credit Facility	$ 202,000	$ 200,000
DEP II Term Loan Agreement	282,250	--
Total principal amount of long-term debt obligations	$ 484,250	$ 200,000

DEP I Revolving Credit Facility

On February 5, 2007, we entered into a $300.0 million variable-rate revolving credit facility (the "DEP I Revolving Credit Facility") having a $30.0 million sublimit for Swingline loans. We may also issue up to $300.0 million of letters of credit under this facility. Letters of credit outstanding under this facility reduce the amount available for borrowings. Amounts borrowed under the DEP I Revolving Credit Facility mature in February 2011; however, 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 dropdown transaction (see Note 1) and the remainder to pay debt issuance costs. At December 31, 2008, the principal balance outstanding under this facility was $202.0 million and letters of credit outstanding totaled $1.0

million. We have hedged a significant portion of our variable interest rate exposure under this loan agreement. See Note 6 for information 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 increasing the commitments of existing lenders. No existing lender is required to increase its commitment, unless it agrees to do so in its sole discretion.

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 and (ii) 0.5% per annum above the Federal Funds Rate in effect on such date.

DEP II Term Loan Agreement

On April 18, 2008, we entered into a standby term loan agreement consisting of commitments for up to a $300.0 million senior unsecured term loan (the "DEP II Term Loan Agreement"). Subsequently, commitments under this 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 dropdown transaction (see Note 1).

Loans under the term loan agreement are due and payable on December 8, 2011. We may also 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 ("ABR") loans or Eurodollar loans. The term loan agreement contains customary affirmative and negative covenants.

Covenants

The DEP I Revolving Credit Facility and DEP II Term Loan Agreements both contain customary affirmative and negative covenants related to our ability to incur certain indebtedness; grant certain liens; enter into merger or consolidation transactions; make certain investments; and other restrictions. The loan agreement also requires us to satisfy certain financial covenants at the end of each fiscal quarter. The loan agreements also restrict our ability to pay cash distributions if a default (as defined in the loan agreements) has occurred and is continuing at the time such distribution is scheduled to be paid. In addition, if an event of default exists under the loan documents, the lenders will be able to accelerate the maturity of amounts borrowed and exercise other rights and remedies. We were in compliance with the covenants of these loan agreements at December 31, 2008 and 2007.

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, 2008.

	Weighted-average interest rate paid
DEP I Revolving Credit Facility	4.25%
DEP II Term Loan Agreement	2.93%

Evangeline joint venture debt obligation

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

	At December 31, 2008	At December 31, 2007
9.9% fixed interest rate senior secured notes due December 2010 ("Series B" notes):		
Current portion of debt – due December 31, 2009	$ 5,000	$ 5,000
Long-term portion of debt	3,150	8,150
$7.5 million subordinated note payable to an affiliate of other co-venture participant ("LL&E Note")	7,500	7,500
Total joint venture debt principal obligation	$ 15,650	$ 20,650

The Series B notes are collateralized by (i) Evangeline's property, plant and equipment; (ii) proceeds from its Entergy natural gas sales contract (see Note 8); 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 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, 2008.

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 a LIBOR rate plus 0.5%. Variable interest rates charged on this note at December 31, 2008, 2007 and 2006 were 3.20%, 5.88% and 6.08% respectively. At December 31, 2008, 2007 and 2006, the amount of accrued but unpaid interest on the LL&E Note was approximately $9.8 million, $9.1 million and $7.9 million, respectively.

Note 11. Partners' Equity and Distributions

We are a Delaware limited partnership formed in September 2006. At December 31, 2008, we are owned 99.3% by our limited partners and 0.7% by our general partner, DEP GP.

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 proceeds of $290.5 million. As consideration for the DEP I dropdown transaction (see Note 1), we distributed $260.6 million of the net 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 dropdown transaction, resulting in a final amount of 5,351,571 common units beneficially owned by EPO.

In December 2008, we distributed $280.5 million from borrowings and issued 37,333,887 Class B units to EPO in connection with the DEP II dropdown transaction. The market value of the Class B units at the transaction date was $449.5 million. At December 31, 2008, the capital account for the Class B units was $453.9 million, which includes the allocation of $4.4 million of net income for the period in which the Class B units were outstanding in December 2008.

We may issue equity or debt securities to assist us in meeting our liquidity and capital spending requirements. On March 6, 2008, we filed a universal shelf registration statement with the SEC to periodically issue up to $1.00 billion in debt and equity securities. We expect to use any proceeds from such offerings for general partnership purposes, including debt repayments, working capital requirements, capital expenditures and business combinations.

On December 8, 2008, in connection with the DEP II dropdown transaction, we issued 41,529 common units to EPO for an aggregate purchase price of $0.5 million, or $12.04 per unit. The price per unit was equal to the closing price per unit on December 5, 2008 as reported by the NYSE. No commissions or discounts were paid in connection with this sale of common units. This sale of common units was registered under our universal shelf registration statement.

Unit History

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

Activity on February 5, 2007:	
Common units originally issued to EPO in connection with the DEP I dropdown transaction	7,301,571
Common units issued in connection with our IPO	14,950,000
Redemption of common units using proceeds from IPO overallotment	(1,950,000)
Common units outstanding, December 31, 2007	20,301,571
Common units sold to EPO in connection with the DEP II dropdown transaction	41,529
Common units outstanding, December 31, 2008	20,343,100

On December 8, 2008, we issued 37,333,887 Class B units to EPO in connection with the DEP II dropdown transaction. The Class B units automatically converted to common units on February 1, 2009.

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**
2007			
1st Quarter (1)	$ 0.2440	April 30, 2007	May 9, 2007
2nd Quarter	0.4000	July 31, 2007	August 8, 2007
3rd Quarter	0.4100	October 31, 2007	November 7, 2007
4th Quarter	0.4100	January 31, 2008	February 7, 2008
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	0.4275	January 30, 2009	February 9, 2009

(1) Our first cash distribution was prorated for the 55-day period from and including February 5, 2007 (the date of our initial public offering) through March 31, 2007 and based on a declared quarterly distribution of $0.40 per unit.

The Class B units received a pro rated cash distribution of $0.1115 per unit for the distribution that DEP paid with respect to the fourth quarter of 2008 for the 24-day period from December 8, 2008, the closing date of the DEP II dropdown transaction, to December 31, 2008.

Note 12. Parent Interest in Subsidiaries

Parent interest in Subsidiaries – DEP I Midstream Businesses

Following completion of the DEP I dropdown transaction effective February 1, 2007, we account for EPO's 34% equity interests in the DEP I Midstream Businesses as "Parent interest" in a manner similar to minority interest. Under this method of presentation, all revenues and expenses of the DEP I Midstream Businesses are included in income from continuing operations, and EPO's share (as Parent) of the income of the DEP I businesses is shown as an adjustment in deriving our net income. In addition, EPO's share of the net assets of the DEP I Midstream Businesses is presented as Parent interest on our consolidated balance sheet.

The DEP I Midstream Businesses distribute their income and operating cash flows in accordance with the following sharing ratios: 66% to Duncan Energy Partners and 34% to EPO. With the exception of special funding arrangements by EPO in connection with the assets owned by South Texas NGL and Mont Belvieu Caverns (as described below), Duncan Energy Partners and EPO make contributions to the DEP I Midstream Businesses in accordance with the previously noted sharing ratios.

Effective with the closing of our IPO in February 2007, we entered into an Omnibus Agreement (see Note 14) with EPO. Under the Omnibus Agreement, EPO agreed to make additional cash contributions to South Texas NGL and Mont Belvieu Caverns to fund 100% of project costs in excess of (i) $28.6 million of estimated costs to complete the Phase II expansion of the DEP South Texas NGL pipeline (a component of our South Texas NGL System) and (ii) $14.1 million of estimated costs for additional Mont Belvieu brine production capacity and above-ground storage reservoir projects. These two projects were in progress at the time of our IPO and the estimated costs of each (as noted above) were based on information available at the time of the DEP I dropdown transaction. EPO made cash contributions to our subsidiaries of $32.5 million and $9.9 million in connection with the Omnibus Agreement during the years ended December 31, 2008 and 2007, respectively. The majority of these contributions related to funding the Phase II expansion costs of the DEP South Texas NGL pipeline. EPO will not receive an increased allocation of earnings or cash flows as a result of these contributions to South Texas NGL and Mont Belvieu Caverns.

The 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 projects from EPO within 90 days of such projects being placed in service. EPO made cash contributions of $99.5 million and $38.1 million under the Caverns LLC Agreement during the years ended December 31, 2008 and 2007, respectively, to fund 100% of certain storage-related projects sponsored by EPO's NGL marketing activities. At present, Mont Belvieu Caverns is not expected to generate any identifiable incremental cash flows in connection with these projects; thus, the sharing ratio for Mont Belvieu Caverns is not expected to change from the current sharing ratio of 66% for Duncan Energy Partners and 34% for EPO. We expect additional contributions of approximately $27.5 million from EPO to fund such projects in 2009. The constructed assets will be the property of Mont Belvieu Caverns.

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. For the two-month period in 2008 covered by the amendment, EPO was allocated (through Parent interest) depreciation expense of $1.0 million related to such projects.

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. Effective with the closing of our IPO, EPO has been allocated (through Parent interest) all operational measurement gains and losses relating to Mont Belvieu Caverns' underground storage activities. As a result, 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 neither affect our net income nor have a significant impact on us with respect to the timing of our net cash flows provided by operating activities. Accordingly, we have not established a reserve for operational measurement losses on our balance sheet.

Storage well measurement gains and losses occur when product movements into a storage well are different than those redelivered to customers. In connection with storage agreements entered into between EPO and Mont Belvieu Caverns effective concurrently with the closing of our IPO, EPO agreed to assume all storage well measurement gains and losses. Such amounts were immaterial to our financial statements for periods prior to the DEP I dropdown transaction (i.e., February 1, 2007).

The following table presents our calculation of "Parent interest in income – DEP I Midstream Businesses" for the eleven months ended December 31, 2007. We allocated income of $20.0 million to EPO as Parent for the eleven month period (February 1 to December 31) following the effective date of the DEP I dropdown transaction, or February 1, 2007.

Mont Belvieu Caverns:		
Mont Belvieu Caverns' net income (before special allocation of operational measurement gains and losses)	$ 22,165	
Deduct operational measurement gain allocated to Parent	(4,537)	$ 4,537
Remaining Mont Belvieu Caverns' net income to allocate to partners	17,628	
Multiplied by Parent 34% interest in remaining net income	x 34%	
Mont Belvieu Caverns' net income allocated to Parent	$ 5,994	5,994
Acadian Gas net income multiplied by Parent 34% interest		1,158
Lou-Tex Propylene net income multiplied by Parent 34% interest		2,552
Sabine Propylene net income multiplied by Parent 34% interest		373
South Texas NGL net income multiplied by Parent 34% interest		5,359
Parent interest in income – DEP I Midstream Businesses (allocated income)		$ 19,973

The following table presents our calculation of "Parent interest in income – DEP I Midstream Businesses" for the year ended December 31, 2008. With respect to the DEP I Midstream Businesses, we allocated income of $11.4 million to EPO as Parent in 2008.

Mont Belvieu Caverns:		
Mont Belvieu Caverns' net income (before special allocation of operational measurement gains and losses)	$ 15,514	
Add operational measurement loss allocated to Parent	6,831	$ (6,831)
Add depreciation expense related to fully funded projects allocated to Parent	984	(984)
Remaining Mont Belvieu Caverns' net income to allocate to partners	23,329	
Multiplied by Parent 34% interest in remaining net income	x 34%	
Mont Belvieu Caverns' net income allocated to Parent	$ 7,932	7,932
Acadian Gas net income multiplied by Parent 34% interest		3,622
Lou-Tex Propylene net income multiplied by Parent 34% interest		2,174
Sabine Propylene net income multiplied by Parent 34% interest		382
South Texas NGL net income multiplied by Parent 34% interest		5,059
Parent interest in income – DEP I Midstream Businesses (allocated income)		$ 11,354

The following table provides a reconciliation of the amounts presented as "Parent interest in Subsidiaries – DEP I Midstream Businesses" on our consolidated balance sheets at December 31, 2007 and 2008.

Fiscal year 2007 transactions:	
Retention by Parent of 34% ownership interest in DEP I Midstream Businesses on February 1, 2007	$ 252,292
Net income of DEP I Midstream Businesses allocated to EPO as Parent – February 1 to December 31, 2007	19,973
Contributions by EPO to DEP I Midstream Businesses – February 1 to December 31, 2007:	
Contributions from EPO to Mont Belvieu Caverns in connection with capital projects in which EPO is funding 100% of the expenditures in accordance with the Mont Belvieu Caverns' LLC Agreement, including accrued receivables at December 31, 2007 (see Note 14)	49,524
Contributions from EPO to Mont Belvieu Caverns and South Texas NGL in connection with capital Projects in which EPO is funding 100% of the expenditures in excess of certain thresholds in Accordance with the Omnibus Agreement, including accrued receivables at December 31, 2007 (see Note 14)	10,952
Other contributions by EPO to the DEP I Midstream Businesses	57,035
Cash distributions to EPO by Mont Belvieu Caverns for operational measurement gains	(4,537)
Cash distributions to EPO of operating cash flows of DEP I Midstream Businesses	(26,901)
Other	(3,209)
December 31, 2007 balance	355,129
Net income of DEP I Midstream Businesses allocated to EPO as Parent	11,354
Contributions by EPO to DEP I Midstream Businesses:	
Contributions from EPO to Mont Belvieu Caverns in connection with capital projects in which EPO is funding 100% of the expenditures in accordance with the Mont Belvieu Caverns' LLC Agreement, including accrued receivables at December 31, 2008 (see Note 14)	88,076
Contributions from EPO to Mont Belvieu Caverns and South Texas NGL in connection with capital Projects in which EPO is funding 100% of the expenditures in excess of certain thresholds in Accordance with the Omnibus Agreement, including accrued receivables at December 31, 2008 (see Note 14)	31,414
Contributions by EPO in connection with operational measurement losses of Mont Belvieu Caverns	6,831
Other contributions by EPO to the DEP I Midstream Businesses	29,669
Cash distributions to EPO of operating cash flows of DEP I Midstream Businesses	(44,105)
December 31, 2008 balance	$ 478,368

Parent interest in Subsidiaries – DEP II Midstream Businesses

Following completion of the DEP II dropdown transaction on December 8, 2008, we account for EPO's equity interests in the DEP II Midstream Businesses as Parent interest. All revenues and expenses of the DEP II Midstream Businesses are included in income from continuing operations, and EPO's share (as Parent) of the income of the DEP II businesses is shown as an adjustment in deriving our net income. In addition, EPO's share of the net assets of the DEP II Midstream Businesses is presented as Parent interest on our consolidated balance sheet.

The total value of the consideration we provided in the DEP II dropdown transaction was $730.0 million, which takes into account our fixed annual return and limited upside potential in the future cash flows of the DEP II Midstream Businesses.The total fair value of the DEP II Midstream Businesses was approximately $3.2 billion. As a result, the $730.0 million in consideration represented the acquisition of 22.6% of the then existing capital accounts of the DEP II Midstream Businesses. EPO retained the remaining 77.4% of the then existing capital accounts. 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, the DEP II dropdown transaction documents provide 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 Enterprise III (based on an initial defined investment of $730.0 million, the "Enterprise III Distribution Base") and then to Enterprise GTM (based on an initial defined investment of $452.1 million, the "Enterprise GTM Distribution Base") in amounts sufficient to generate an aggregate annualized fixed return on their respective investments of 11.85% (see below). Distributions in excess of these amounts will be distributed 98% to Enterprise GTM and 2% to Enterprise III.

The initial fixed annual return is 11.85%. This initial fixed return was determined by the parties based on our estimated weighted-average cost of capital at December 8, 2008, plus 1.0%. The fixed return will be increased by 2.0% each calendar year. The initial Enterprise III Distribution Base and the Enterprise GTM Distribution Base amounts represent negotiated values between us and EPO and affiliates. If Enterprise III participates in an expansion project in any of the DEP II Midstream Businesses, it may request an incremental adjustment to the then-applicable fixed return to reflect its (or its affiliates') weighted-average cost of capital associated with such contribution. To the extent that Enterprise III and/or Enterprise GTM make capital contributions to fund expansion capital projects at any of 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.

Income and loss of the DEP II Midstream Businesses is first allocated to Enterprise III and Enterprise GTM 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 entity. 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) exceeds the amount we would have been entitled to receive (or required to fund) based solely on our Percentage Interest. This special earnings allocation to us reduces the amount of income allocated to EPO by an equal amount and may result in EPO being allocated a loss when we are allocated income. It is our expectation that EPO will be allocated a loss by the DEP II Midstream Businesses until such time as growth projects such as the Sherman Extension realize their income and cash flow potential. Our participation in this expected increase in cash flow from growth projects is limited (beyond our fixed annual return amount) to 2% of such upside, with Enterprise GTM receiving 98% of the benefit.

The following table presents our calculation of "Parent interest in income – DEP II Midstream Businesses" for the period from December 8, 2008 to December 31, 2008. We attributed a loss of $4.0 million to EPO (as Parent) for this period following the closing of the DEP II dropdown transaction.

DEP II Midstream Businesses - Base earnings allocation to EPO as Parent (77.4%)		$ 368
Additional income allocation to Duncan Energy Partners:		
Total distributions paid by DEP II Midstream Businesses	$ 5,435	
Duncan Energy Partners' Percentage Interest in total distributions (22.6%)	1,228	
Less distributions paid to Duncan Energy Partners (based on fixed annual return)	5,581	(4,353)
Parent interest in income – DEP II Midstream Businesses (attributed loss)		$ (3,985)

The following table provides a reconciliation of the amounts presented as "Parent interest in Subsidiaries – DEP II Midstream Businesses" on our consolidated balance sheet at December 31, 2008. Amounts are for the period from the closing of the dropdown transaction to December 31, 2008.

Retention by Parent of ownership interest in DEP II Midstream Businesses on December 8, 2008	$ 2,595,507
Allocated loss from DEP II Midstream Businesses to EPO as Parent – December 8 to December 31, 2008	(3,985)
Contributions by EPO in connection with expansion cash calls	21,331
Distributions to Parent of subsidiary operating cash flows	(804)
Other general cash contributions from Parent	955
December 31, 2008 balance	$ 2,613,004

Enterprise III has declined participation in expansion project spending since December 8, 2008. As a result, Enterprise GTM has funded 100% of such growth capital spending, which amount to $21.3 million since the closing date of the DEP II dropdown transaction.

For additional information regarding our agreements with EPO in connection with the DEP II dropdown transaction, see "Relationship with EPO – Company and Limited Partnership Agreements – DEP II Midstream Businesses" under Note 14.

Note 13. 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. Effective with the fourth quarter of 2008, our segment information has been recast as a result of the DEP II dropdown transaction.

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 senior management in deciding how to allocate capital resources among business segments. We believe that investors benefit from having access to the same financial measures that our management uses in evaluating segment results. The GAAP measure most directly comparable to total segment gross operating margin is operating income. Our non-GAAP financial measure of total segment gross operating margin should not be considered as an alternative to GAAP operating income.

We define total segment gross operating margin as operating income before: (i) depreciation, amortization and accretion expense; (ii) gains and losses on asset sales and related transactions; and (iii) general and administrative expenses. Gross operating margin is exclusive of other income and expense transactions, provision for income taxes, minority interest, extraordinary charges and the cumulative effect of changes in accounting principles. 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.

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.

Consolidated property, plant and equipment and investments in and advances to our unconsolidated affiliate are allocated to each segment based on the primary operations of each asset or investment. The principal reconciling item between consolidated property, plant and equipment and the total value of segment assets is construction-in-progress. Segment assets represent the net carrying value of assets that contribute to the gross operating margin of a particular segment. Since assets under construction generally do not contribute to segment gross operating margin until completed, such assets are excluded from segment asset totals until they are deemed operational.

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

		For the Year Ended December 31,		
		2008	**2007**	**2006**
Revenues (1)		$ 1,598,068	$ 1,220,292	$ 1,263,028
Less:	Operating costs and expenses (1)	(1,512,806)	(1,170,942)	(1,200,872)
Add:	Equity in income of unconsolidated affiliate (1)	896	182	958
	Depreciation, amortization and accretion in operating costs and expenses (2)	167,380	175,308	155,998
	Loss (gain) on asset sales and related transactions in operating costs and expenses (2)	(532)	(80)	(26)
Total segment gross operating margin		$ 253,006	$ 224,760	$ 219,086

(1) These amounts are taken from our Statements of Consolidated Operations and Comprehensive Income.

(2) These non-cash expenses are taken from the operating activities section of our Statements of Consolidated Cash Flows.

The following table presents a reconciliation of total segment gross operating margin to operating income and income before the cumulative effect of changes in accounting principles for the periods noted:

	For the Year Ended December 31,		
	2008	**2007**	**2006**
Total segment gross operating margin	$ 253,006	$ 224,760	$ 219,086
Adjustments to reconcile total segment gross operating margin to operating income:			
Depreciation, amortization and accretion in operating costs and expenses	(167,380)	(175,308)	(155,998)
Gain (loss) on asset sales and related transactions in operating costs and expenses	532	80	26
General and administrative costs	(18,305)	(13,116)	(10,227)
Consolidated operating income	67,853	36,416	52,887
Other income (expense), net	(11,443)	(8,645)	459
Provision for income taxes	(1,095)	(4,172)	(1,682)
Parent interest in income of subsidiaries	(7,369)	(19,973)	--
Income before cumulative effect of changes in accounting principles	$ 47,946	$ 3,626	$ 51,664

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

	Natural Gas Pipelines & Services	Petrochemical Services	NGL Pipelines & Services	Adjustments and Eliminations	Consolidated Totals
Revenues from third parties:					
Year ended December 31, 2008	$ 773,150	$ 14,203	$ 69,067	$ --	$ 856,420
Year ended December 31, 2007	685,117	14,401	59,772	(36)	759,254
Year ended December 31, 2006	702,217	--	56,833	(30)	759,020
Revenues from related parties:					
Year ended December 31, 2008	582,153	--	159,495	--	741,648
Year ended December 31, 2007	323,251	2,990	134,797	--	461,038
Year ended December 31, 2006	361,313	39,087	103,608	--	504,008
Total revenues:					
Year ended December 31, 2008	1,355,303	14,203	228,562	--	1,598,068
Year ended December 31, 2007	1,008,368	17,391	194,569	(36)	1,220,292
Year ended December 31, 2006	1,063,530	39,087	160,441	(30)	1,263,028
Equity in income of Evangeline:					
Year ended December 31, 2008	896	--	--	--	896
Year ended December 31, 2007	182	--	--	--	182
Year ended December 31, 2006	958	--	--	--	958
Gross operating margin by individual business segment and in total:					
Year ended December 31, 2008	159,022	11,105	82,879	--	253,006
Year ended December 31, 2007	122,486	14,349	87,925	--	224,760
Year ended December 31, 2006	123,983	35,710	59,393	--	219,086
Segment assets:					
At December 31, 2008	2,887,579	86,609	897,070	458,962	4,330,220
At December 31, 2007	2,693,840	89,634	697,288	257,246	3,738,008
Investments in and advances to Evangeline (see Note 8):					
At December 31, 2008	4,527	--	--	--	4,527
At December 31, 2007	3,490	--	--	--	3,490
Intangible assets					
At December 31, 2008	13,402	--	38,860	--	52,262
At December 31, 2007	14,938	--	33,645	--	48,583
Goodwill					
At December 31, 2008	4,400	--	500	--	4,900
At December 31, 2007	4,400	--	500	--	4,900

Our consolidated revenues were earned in the United States. Our operations are located in Texas and Louisiana. A related party, Evangeline, is our largest customer and accounted for 22.7%, 21.7% and 22.0% of our consolidated revenues in 2008, 2007 and 2006, respectively. Related party revenues from Evangeline are attributable to the sale of natural gas and are presented in our Natural Gas Pipelines & Services business segment. Sales to Evangeline totaled $362.9 million, $264.2 million and $277.7 million for the years ended December 31, 2008, 2007 and 2006, respectively.

Our largest third party customer was Exxon Mobil and affiliates, which accounted for 10.0%, 7.6% and 7.3% of our consolidated revenues in 2008, 2007 and 2006, respectively. The majority of our revenues from Exxon Mobil are derived from the sale and transportation of natural gas and are also presented in our Natural Gas Pipelines & Services business segment. Sales to Exxon Mobil totaled $159.2 million, $93.2 million and $92.0 million for the years ended December 31, 2008, 2007 and 2006, 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,		
	2008	2007	2006
Natural Gas Pipelines & Services:			
Sales of natural gas	$ 1,029,835	$ 742,898	$ 815,797
Natural gas transportation services	317,107	263,959	241,548
Natural gas storage services	8,361	1,475	6,155
Total	$ 1,355,303	$ 1,008,332	$ 1,063,500
NGL Pipelines & Services:			
Sales of NGLs	$ 47,899	$ 40,338	$ 36,263
Sales of other products	15,017	10,776	11,201
NGL and petrochemical storage services	87,429	68,912	56,791
NGL fractionation services	32,370	30,253	29,630
NGL transportation services	43,605	42,542	23,748
Other services	2,242	1,748	2,808
Total	$ 228,562	$ 194,569	$ 160,441
Petrochemical Services:			
Propylene transportation services	$ 14,203	$ 17,391	$ 39,087
Total consolidated revenues	$ 1,598,068	$ 1,220,292	$ 1,263,028
Consolidated cost and expenses			
Operating costs and expenses:			
Cost of natural gas and NGL sales	$ 1,057,992	$ 765,116	$ 833,490
Depreciation, amortization and accretion	167,380	175,308	155,998
Loss (gain) on asset sales and related transactions	(532)	(80)	(26)
Other operating expenses	287,966	230,598	211,410
General and administrative costs	18,305	13,116	10,227
Total consolidated costs and expenses	$ 1,531,111	$ 1,184,058	$ 1,211,099

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 14. Related Party Transactions

The following information summarizes our business relationships and transactions with related parties during the year ended December 31, 2008. 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.

The following table summarizes our consolidated revenue and expense transactions with related parties for the periods indicated:

	For the Year Ended December 31,		
	2008	**2007**	**2006**
Revenues:			
Revenues from EPO:			
Sales of natural gas	$ 165,984	$ 22,762	$ 59,036
Natural gas transportation services	32,283	21,846	11,681
Natural gas storage services	875	--	66
Sales of NGLs	52,909	41,226	35,856
NGL and petrochemical storage services	33,774	28,853	20,113
NGL fractionation services	28,345	30,253	29,629
NGL transportation services	22,981	27,239	10,115
Other natural gas and NGL related services	39,323	24,134	59,745
Sales of natural gas – Evangeline	362,890	264,248	277,741
Natural gas transportation services – Energy Transfer Equity	903	437	--
NGL and petrochemical storage services – TEPPCO	1,381	40	26
Total related party revenues	$ 741,648	$ 461,038	$ 504,008
Operating costs and expenses:			
EPCO administrative services agreement	$ 72,048	$ 63,710	$ 65,474
Expenses with EPO:			
Purchases of natural gas	229,932	29,071	12,355
Operational measurement losses (gains)	6,831	(4,537)	--
Other expenses with EPO	18,619	7,480	(1)
Purchases of natural gas – Nautilus	10,250	3,531	1,573
Expenses with Energy Transfer Equity:			
Purchases of natural gas	7,294	5,628	--
Operating cost reimbursements for shared facilities	(2,789)	(1,746)	--
Other expenses with Energy Transfer Equity	3,133	1,088	--
Expenses with TEPPCO	(194)	(74)	(154)
Other related party expenses, primarily with Evangeline	14	110	2
Total related party operating costs and expenses	$ 345,138	$ 104,261	$ 79,249
General and administrative costs:			
EPCO administrative services agreement	$ 15,663	$ 11,480	$ 10,157
Other related party general and administrative costs	(781)	(65)	--
Total related party general and administrative costs	$ 14,882	$ 11,415	$ 10,157

One of our principal advantages is our relationship with EPO and EPCO. EPO is a wholly owned subsidiary of Enterprise Products Partners through which Enterprise Products Partners conducts its business. Enterprise Products Partners is controlled by its general partner, Enterprise Products GP, LLC (“EPGP”), which in turn is a wholly owned subsidiary of Enterprise GP Holdings. The general partner of Enterprise GP Holdings is EPE Holdings, LLC (“EPE Holdings”), which is a wholly owned subsidiary of a private company controlled by Dan L. Duncan. Mr. Duncan is Chairman of our general partner and is a Group Co-Chairman and the controlling shareholder of EPCO. Our general partner is wholly owned by EPO and EPCO provides all of our employees, including our executive officers.

Relationship 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 growth objectives of EPO and other affiliates under common control.

At December 31, 2008, EPO owned approximately 74% of our limited partner interests and 100% of our general partner. EPO was sponsor of the DEP I and DEP II dropdown 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 dropdown transactions (including consideration provided to EPO), see Note 1. For a description of EPO's Parent interest in the income and net assets of the DEP I and DEP II Midstream Businesses, see Note 12. 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.

A significant portion of our related party revenues from EPO are attributable to the sale of natural gas and NGLs and the provision of storage services. For 2008, EPO accounted for 23.6% of our consolidated revenues. Our related party expenses with EPO primarily involve the purchase of natural gas by Acadian Gas. Acadian Gas sells natural gas to Evangeline (an unconsolidated affiliate - see "Relationship with Evangeline" within this Note 14) that, in turn, enables Evangeline to meet its commitment under a sales contract with a third party utility customer.

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 dropdown 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 (estimated at $1.4 million) 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 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 administrative services agreement, 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 dropdown transactions. These indemnifications terminate 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, 2008 and 2007.

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 "Parent Interest in Subsidiaries – DEP I Midstream Businesses" under Note 12.

Mont Belvieu Caverns' LLC Agreement. The 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 projects 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 "Parent Interest in Subsidiaries – DEP I Midstream Businesses" under Note 12.

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 dropdown transaction. Collectively, these amended and restated agreements provide for the following:

§ the acquisition by Enterprise III (our wholly owned subsidiary) from Enterprise GTM (a wholly owned subsidiary of 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 Enterprise III (based on an initial defined investment of $730.0 million, the "Enterprise III Distribution Base") and then to Enterprise GTM (based on an initial defined investment of $452.1 million, the "Enterprise GTM Distribution Base") 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 Enterprise GTM and 2.0% to Enterprise III. 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, Enterprise III has elected to not participate in such cash calls and, as a result, Enterprise GTM has funded 100% of the expansion project costs of the DEP II Midstream Businesses. If Enterprise III later elects to participate in an expansion projects, then Enterprise III will be required to make a capital contribution for its share of the project costs.

Any capital contributions to fund expansion projects made by either Enterprise III or Enterprise GTM will increase such partner's Distribution Base (and hence future priority return amounts) under the Company Agreement of Enterprise Texas. As noted, Enterprise III has declined participation in expansion project spending since December 8, 2008. As a result, Enterprise GTM has funded 100% of such growth capital spending and its Distribution Base has increased from $452.1 million at December 8, 2008 to $473.4 million at December 31, 2008. The Enterprise III Distribution Base was unchanged at $730.0 million at December 31, 2008.

Relationship with EPCO

We have no employees. All of our operating functions and general and administrative support services are provided by employees of EPCO pursuant to an administrative services agreement (the "ASA"). We, Enterprise Products Partners, Enterprise GP Holdings, TEPPCO Partners, L.P. ("TEPPCO") 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 for the year ended December 31, 2008 include reimbursement payments 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. Such reimbursements were $72.0 million during the year ended December 31, 2008.

Likewise, our general and administrative costs for the year ended December 31, 2008 includes amounts we reimburse 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 ASA based on the estimated use of such services by each party (e.g., the allocation of general legal or accounting salaries based on estimates of time spent on each entity's business and affairs). Such reimbursements were $15.7 million during the year ended December 31, 2008.

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. With respect to potential conflicts, the ASA provides, among other things, that:

- If a business opportunity to acquire "equity securities" (as defined below) is presented to the EPCO Group, Enterprise Products Partners (including EPGP), Enterprise GP Holdings (including EPE Holdings), Duncan Energy Partners (including DEP GP), then Enterprise GP Holdings will have the first right to pursue such opportunity. The term "equity securities" is defined to include:

  - general partner interests (or securities which have characteristics similar to general partner interests) or interests in "persons" that own or control such general partner or similar interests (collectively, "GP Interests") and securities convertible, exercisable, exchangeable or otherwise representing ownership or control of such GP Interests; and

  - incentive distribution rights and limited partner interests (or securities which have characteristics similar to incentive distribution rights or limited partner interests) in publicly traded partnerships or interests in "persons" that own or control such limited partner or similar interests (collectively, "non-GP Interests"); provided that such non-GP Interests are associated with GP Interests and are owned by the owners of GP Interests or their respective affiliates.

  Enterprise GP Holdings will be presumed to want to acquire the equity securities until such time as EPE Holdings advises the EPCO Group, EPGP and DEP GP that it has abandoned the pursuit of such business opportunity. In the event that the purchase price of the equity securities is reasonably likely to equal or exceed $100 million, the decision to decline the acquisition will be made by the Chief Executive Officer of EPE Holdings after consultation with and subject to the approval of the ACG Committee of EPE Holdings. If the purchase price is reasonably likely to be less than $100 million, the Chief Executive Officer of EPE Holdings may make the determination to decline the acquisition without consulting the ACG Committee of EPE Holdings.

  In the event that Enterprise GP Holdings abandons the acquisition and so notifies the EPCO Group, EPGP and DEP GP, Enterprise Products Partners will have the second right to pursue such acquisition. Enterprise Products Partners will be presumed to want to acquire the equity securities until such time as EPGP advises the EPCO Group and DEP GP that Enterprise Products Partners has abandoned the pursuit of such acquisition. In determining whether or not to pursue the acquisition, Enterprise Products Partners will follow the same procedures applicable to Enterprise GP Holdings, as described above but utilizing EPGP's Chief Executive Officer and ACG Committee.

  In its sole discretion, Enterprise Products Partners may affirmatively direct such acquisition opportunity to Duncan Energy Partners. In the event this occurs, Duncan Energy Partners may pursue such acquisition.

  In the event Enterprise Products Partners abandons the acquisition opportunity for the equity securities and so notifies the EPCO Group and DEP GP, the EPCO Group may pursue the acquisition or offer the opportunity to TEPPCO (including its general partner) and their controlled affiliates, in either case, without any further obligation to any other party or offer such opportunity to other affiliates.

- If any business opportunity not covered by the preceding bullet point (i.e. not involving "equity securities") is presented to the EPCO Group, Enterprise Products Partners (including EPGP), Enterprise GP Holdings (including EPE Holdings), or Duncan Energy Partners (including DEP GP), Enterprise Products Partners will have the first right to pursue such opportunity either for itself or, if desired by Enterprise Products Partners in its sole discretion, for the benefit of Duncan Energy Partners. It will be presumed that Enterprise Products Partners will pursue the business opportunity until such time as its general partner advises the EPCO Group, EPE Holdings and DEP GP that it has abandoned the pursuit of such business opportunity.

  In the event the purchase price or cost associated with the business opportunity is reasonably likely to equal or exceed $100 million, any decision to decline the business opportunity will be made by the Chief Executive Officer of EPGP after consultation with and subject to the approval of the ACG Committee of EPGP. If the purchase price or cost is reasonably likely to be less than $100 million, the Chief Executive Officer of EPGP may make the determination to decline the business opportunity without consulting EPGP's ACG Committee.

In its sole discretion, Enterprise Products Partners may affirmatively direct such acquisition opportunity to Duncan Energy Partners. In the event this occurs, Duncan Energy Partners may pursue such acquisition.

In the event that Enterprise Products Partners abandons the business opportunity for itself and Duncan Energy Partners and so notifies the EPCO Group, EPE Holdings and DEP GP, Enterprise GP Holdings will have the second right to pursue such business opportunity. It will be presumed that Enterprise GP Holdings will pursue such acquisition until such time as its general partner declines such opportunity (in accordance with the procedures described above for Enterprise Products Partners) and advises the EPCO Group that it has abandoned the pursuit of such business opportunity. Should this occur, the EPCO Group may either pursue the business opportunity or offer the business opportunity to TEPPCO (including its general partner) and their controlled affiliates without any further obligation to any other party or offer such opportunity to other affiliates.

None of Enterprise Products Partners, Enterprise GP Holdings, Duncan Energy Partners or their respective general partners or the EPCO Group have any obligation to present business opportunities to TEPPCO (including its general partner) or their controlled affiliates. Likewise, TEPPCO (including its general partner) and their controlled affiliates have no obligation to present business opportunities to Enterprise Products Partners, Enterprise GP Holdings, Duncan Energy Partners or their respective general partners or the EPCO Group.

The ASA was amended on January 30, 2009 to provide for the cash reimbursement by us, Enterprise Products Partners, TEPPCO 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.

Employee Partnerships. EPCO formed the Employee Partnerships to serve as an incentive arrangement for key employees of EPCO by providing them a "profits interest" in such partnerships. Certain EPCO employees who work on behalf of us and EPCO were issued Class B limited partner interests and admitted as Class B limited partners of the Employee Partnerships without any capital contribution. The profits interest awards (i.e., the Class B limited partner interests) in the Employee Partnerships entitle the holder to participate in the appreciation in value of the underlying limited partner interest owned by the Employee Partnership. For additional information regarding the Employee Partnerships, see Note 5.

Relationship with Evangeline

Evangeline has entered into a natural gas purchase contract with Acadian Gas that contains annual purchase provisions. The pricing terms of the purchase agreement are based on a monthly weighted-average market price of natural gas (subject to certain market index price ceilings and incentive margins) plus a predetermined margin. Acadian Gas sold $362.9 million, $264.2 million and $277.7 million of natural gas to Evangeline during the years ended December 31, 2008, 2007 and 2006, respectively. The amount of natural gas purchased by Evangeline pursuant to this contract totaled 18.0 BBtus, 18.2 BBtus and 17.9 BBtus during 2008, 2007 and 2006, respectively. Evangeline is our largest customer and accounted for 22.7%, 21.7% and 22.0% of our consolidated revenues in 2008, 2007 and 2006, respectively.

EPO has furnished letters of credit on behalf of Evangeline's debt service requirements. The outstanding letters of credit totaled $1.0 million, at December 31, 2008.

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.

Relationship 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.

Note 15. Earnings Per Unit

Basic earnings per unit is computed by dividing net income or loss allocated to limited partner interests by the weighted-average number of distribution-bearing common and Class B units (see Note 11) outstanding during a period. The Class B units received a pro-rated distribution with respect to the fourth quarter of 2008 based on the same distribution paid to our common unitholders. On February 1, 2009, the Class B units automatically converted on a one-for-one basis to common units. 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,	
	2008	**2007**
Net income	$ 47,946	$ 3,626
Less: Income allocated to former owner of DEP I Midstream Businesses	--	5,035
Income (loss) allocated to former owners of DEP II Midstream Businesses	19,604	(20,641)
Net income allocated to Duncan Energy Partners	28,342	19,232
Multiplied by DEP GP ownership interest (weighted-average for period)	1.7%	2.0%
Net income allocation to DEP GP	$ 492	$ 385

From the closing of our IPO 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 dropdown 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,	
	2008	2007
Net income allocation to Duncan Energy Partners	$ 28,342	$ 19,232
Less: Income allocation to DEP GP	492	385
Net income allocation to limited partners	$ 27,850	$ 18,847
Basic and diluted earnings per unit:		
Numerator (net income allocation to limited partners)	$ 27,850	$ 18,847
Denominator (weighted-average units outstanding):		
Common units	20,304	20,302
Class B units	2,448	--
Total units	22,752	20,302
Earnings per unit	$ 1.22	$ 0.93

Note 16. 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 significant litigation, pending or threatened, that may have a significant adverse effect on our financial position or results of operations.

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, 2008, NGL and petrochemical products aggregating 22.5 million barrels were due to be redelivered to their owners along with 6,371 BBtus of natural gas. See Note 2 for more information regarding accrued product payables.

Contractual Obligations

The following table summarizes our significant contractual obligations at December 31, 2008. A description of each type of contractual obligation follows:

	Payment or Settlement due by Period						
Contractual Obligations (1)	**Total**	**2009**	**2010**	**2011**	**2012**	**2013**	**Thereafter**
Scheduled maturities of long term debt (2)	$ 482,250	$ --	$ --	$ 482,250	$ --	$ --	$ --
Estimated cash interest payments (3)	$ 49,127	$ 20,152	$ 19,301	$ 9,674	$ --	$ --	$ --
Operating lease obligations	$ 126,441	$ 10,676	$ 9,214	$ 9,105	$ 8,639	$ 7,353	$ 81,454
Purchase obligations:							
Product purchase commitments:							
Estimated payment obligations:							
Natural gas	$ 508,488	$ 127,035	$ 127,035	$ 127,035	$ 127,383	$ --	$ --
Other	$ 245	$ 119	$ 42	$ 42	$ 42	$ --	$ --
Underlying major volume commitments:							
Natural gas (in BBtus)	73,050	18,250	18,250	18,250	18,300	--	--
Capital expenditure commitments (4)	$ 126,805	$ 126,805	$ --	$ --	$ --	$ --	$ --

(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 10 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, 2008. With respect to variable-rate debt, we applied the weighted-average interest rates paid during 2008. See Note 10 for information regarding variable interest rates charged in 2008 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, 2008. See Note 6 for information regarding our financial instruments.

(4) Capital expenditure commitments are reflected on a 100% basis before contributions from the Parent in connection with the Omnibus Agreement and Mont Belvieu Caverns' limited liability company agreement (see Note 14).

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, 2008, 2007 or 2006; however, we did incur $9.3 million of repair costs associated with our lease of the Wilson facility in 2006. Lease expense included in costs and expenses was $10.8 million, $9.9 million and $9.4 million for the twelve months ended December 31, 2008, 2007 and 2006, respectively.

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.

Acadian Gas has a product purchase commitment for the purchase of natural gas in Louisiana (see Note 8) that expires in January 2013. Our purchase price under this contract approximates the market price of natural gas at the time we take delivery of the volumes. The contractual obligations table shows the volume we are committed to purchase and an estimate of our future payment obligations for the periods indicated. Our estimated future payment obligations are based on the contractual price at December 31, 2008 applied to all future volume commitments. Actual future payment obligations may vary depending on market prices at the time of delivery.

At December 31, 2008, 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, 2008, we had approximately $126.8 million in outstanding capital expenditure commitments. These commitments primarily relate to announced expansions of the Texas Intrastate System (i.e., the Sherman Extension and Trinity River Basin Extension). At present, we have elected to not participate in these expansion projects; therefore, EPO will fund 100% of such project 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 14.

Note 17. 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 and fractionation; (ii) storage of NGL and petrochemical products; (iii) transportation of petrochemical products (iv) the gathering, transportation, storage of natural gas; and (v) the marketing of NGLs and natural gas. As such, our results of operations, cash flows and financial condition 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.

A related party, Evangeline, is our largest customer and accounted for 22.7%, 21.7% and 22.0% of our consolidated revenues in 2008, 2007 and 2006, respectively. Our largest third party customer was Exxon Mobil and affiliates, which accounted for 10.0%, 7.6% and 7.3% of our consolidated revenues in 2008, 2007 and 2006, respectively.

Counterparty Risk with Respect to Financial Instruments

In those situations where we are exposed to credit risk in our financial 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.

Weather-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 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 combined 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 repair costs or lost income. Any event that interrupts the revenues generated by our combined operations, or which causes us to make significant expenditures not covered by insurance, could reduce our ability to pay distributions to owners.

For windstorm events such as hurricanes and tropical storms, EPCO's deductible for onshore physical damage is $10.0 million per storm. For non-windstorm events, EPCO's deductible for onshore physical damage is $5.0 million per occurrence. In meeting the deductible amounts, property damage costs are aggregated for EPCO and its affiliates, including us. Accordingly, our exposure with respect to the deductibles may be equal to or less than the stated amounts depending on whether other EPCO or affiliate assets are also affected by an event. To qualify for business interruption coverage, covered onshore assets must be out-of-service in excess of 60 days.

In the third quarter of 2008, certain of our facilities were adversely impacted by Hurricanes Gustav and Ike. As a result of our allocated share of EPCO's insurance deductibles for windstorm coverage, we expensed a combined $1.7 million of repair costs for property damage in connection with these two storms. We expect to file property damage insurance claims to the extent repair costs exceed this amount. Due to the recent nature of these storms, we are still evaluating the total cost of repairs and the potential for business interruption claims.

Note 18. Supplemental Cash Flow Information

Third parties may be obligated to reimburse us for all or a portion of expenditures on certain of our capital projects. The majority of such arrangements are associated with projects related to pipeline construction and production well tie-ins. We received $9.9 million, $10.1 million and $39.5 million as contributions in aid of our construction costs during the years ended December 31, 2008, 2007 and 2006, respectively.

We determine net cash flows provided by operating activities using the indirect method, which adjusts net income for items that did not affect cash. Under GAAP, we use the accrual basis of accounting to determine net income. This basis of accounting requires that we record revenue when earned and expenses when incurred. Earned revenues may include credit sales that have not been collected in cash and expenses incurred that may not have been paid in cash. The extent to which changes in operating accounts influence net cash flows provided by operating activities generally depends on the following:

§ The timing of cash receipts from revenue transactions and cash payments for expense transactions near the end of each reporting period. For example, if significant cash receipts are posted on the last day of the current reporting period, but subsequent payments on expense invoices are made on the first day of the next reporting period, net cash flows provided by operating activities will reflect an increase in the current reporting period that will be reduced as payments are made in the next period. We employ prudent cash management practices and monitor our daily cash requirements to meet our ongoing liquidity needs.

§ If commodity or other prices increase between reporting periods, changes in accounts receivable and accounts payable and accrued expenses may appear larger than in previous periods; however, overall levels of receivables and payables may still reflect normal ranges. From a receivables standpoint, we monitor the amount of credit extended to customers.

§ Additions to inventory for forward sales transactions or other reasons or increased expenditures for prepaid items would be reflected as a use of cash and reduce overall cash provided by operating activities in a given reporting period. As these assets are charged to expense in subsequent periods, the expense amount is reflected as a positive change in operating accounts; however, there is no impact on operating cash flows.

In addition to the adjustments noted above, non-cash charges in the income statement are added back to net income and non-cash credits are deducted to compute net cash flows provided by operating activities. Examples of non-cash charges include depreciation and amortization.

The net effect of changes in operating assets and liabilities is as follows for the periods indicated:

	For the Year Ended December 31,		
	2008	**2007**	**2006**
Decrease (increase) in:			
Accounts receivable - trade	$ 5,033	$ 9,729	$ 35,731
Accounts receivable - related party	1,209	(4,230)	
Gas imbalance receivables	(1,417)	28,665	11,797
Inventories	(6,021)	(6,808)	(2,185)
Prepaid and other current assets	1,555	(1,499)	(415)
Other assets	--	--	(7)
Increase (decrease) in:			
Accounts payable - trade	(5,938)	15,804	(5,725)
Accounts payable - related party	13,523	30,978	--
Accrued costs and expenses	(10,120)	(47,745)	(54,460)
Other current liabilities	12,925	(11,560)	2,989
Other long-term liabilities	(12,499)	777	(397)
Net effect of changes in operating accounts	$ (1,750)	$ 14,111	$ (12,672)

Cash payments for interest, net of amounts capitalized, were $11.5 million for each of the years ended December 31, 2008 and 2007. Capitalized interest was $0.3 million and $2.6 million for 2008 and 2007, respectively. We did not have any debt until the closing of our IPO in February 2007.

Cash payments for income taxes were $0.2 million for the year ended December 31, 2008. There were no cash payments for income taxes for the years ended December 31, 2007 and 2006.

We incurred liabilities for construction in progress that had not been paid at December 31, 2008, 2007 and 2006 of $30.5 million, $24.8 million and $14.3 million, respectively. Such amounts are not included under the caption "Capital expenditures" on the Statements of Consolidated Cash Flows.

Cash payments for business combinations were $35.0 million and $11.7 million for the years ended December 31, 2007 and 2006. In 2006, we used $11.7 million to purchase certain idle Houston-area pipeline segments from TEPPCO. 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. The following table presents our allocation of the acquisition costs at December 31, 2007 and 2008. During 2008, we made non-cash reclassification adjustments to our December 31, 2007 preliminary values. Amounts at December 31, 2008 represent final values and were derived using recognized business valuation techniques.

	Allocation of Acquisition Costs	2008 Adjustments	Total
Assets acquired in business combination:			
Current assets	$ --	$ 35	$ 35
Property, plant and equipment, net	36,000	(12,781)	23,219
Intangible assets	--	12,747	12,747
Total assets acquired	36,000	1	36,001
Liabilities assumed in business combination:			
Other long-term liabilities	(1,000)	--	(1,000)
Total liabilities assumed	(1,000)	--	(1,000)
Total assets acquired plus liabilities assumed	35,000	1	35,001
Total cash used for business combinations	35,000	1	35,001
Goodwill	$ --	$ --	$ --

On a pro forma basis, the South Monco business combination would have had an immaterial impact on our earnings per unit.

Note 19. Quarterly Financial Information (Unaudited)

The following table presents selected quarterly financial data for the years ended December 31, 2008 and 2007:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
For the Year Ended December 31, 2008:				
Revenues	$ 363,558	$ 478,886	$ 432,220	$ 323,404
Operating income	21,047	15,854	18,730	12,222
Parent interest in income of subsidiaries	(5,616)	599	(4,348)	1,996
Net income	13,292	13,279	10,622	10,753
Net income allocation:				
Limited partners	5,911	6,472	3,727	11,740
General partner	121	132	76	163
Former owner of DEP II Midstream Businesses	7,260	6,675	6,819	(1,150)
Earnings per unit (basic and diluted)	0.29	0.32	0.18	0.39
For the Year Ended December 31, 2007:				
Revenues	282,820	328,131	307,832	301,509
Operating income	9,803	5,619	4,424	16,570
Parent interest in income of subsidiaries	(4,049)	(6,603)	(3,188)	(6,133)
Net income	714	(2,430)	(1,443)	6,785
Net income allocation:				
Limited partners	3,845	4,457	4,404	6,142
General partner	78	91	90	125
Former owner of DEP I Midstream Businesses	5,035	--	--	--
Former owner of DEP II Midstream Businesses	(8,244)	(6,978)	(5,937)	518
Earnings per unit (basic and diluted)	0.19	0.22	0.22	0.30

Our historical financial information has been recast for all periods in connection with the DEP II dropdown transaction. See Note 1 for information regarding the basis of our financial statement presentation.

DUNCAN ENERGY PARTNERS L.P.
COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES
(Dollars in thousands)

	For the Years Ended December 31,				
	2008	**2007**	**2006**	**2005**	**2004**
Consolidated income	$ 47,946	$ 3,626	$ 51,682	$ 30,123	$ 54,383
Add: Parent interest in income of subsidiaries – DEP I Midstream Businesses	11,354	19,973	--	--	--
Parent interest in income of subsidiaries – DEP II Midstream Businesses	(3,985)	--	--	--	--
Provision for income taxes	1,095	4,172	1,682	--	--
Less: Equity in (income) loss of Evangeline	(896)	(182)	(958)	(331)	(231)
Consolidated pre-tax income before parent interest in income of subsidiaries and equity earnings from Evangeline	55,514	27,589	52,406	29,792	54,152
Add: Fixed charges	15,319	14,538	3,219	3,079	1,089
Amortization of capitalized interest	1,015	590	--	--	--
Subtotal	71,848	42,717	55,625	32,871	55,241
Less: Interest capitalized	(312)	(2,600)	--	--	--
Parent interest in income of subsidiaries – DEP I Midstream Businesses	(11,354)	(19,973)	--	--	--
Parent interest in income of subsidiaries – DEP II Midstream Businesses	3,985	--	--	--	--
Total earnings	$ 64,167	$ 20,144	$ 55,625	$ 32,871	$ 55,241
Fixed charges:					
Interest expense	$ 11,420	$ 8,641	$ --	$ --	$ --
Capitalized interest	312	2,600	--	--	--
Interest portion of rental expense	3,587	3,297	3,219	3,079	1,089
Total	$ 15,319	$ 14,538	$ 3,219	$ 3,079	$ 1,089
Ratio of earnings to fixed assets	4.19x	1.39x	17.28	10.68x	50.71x

These computations take into account our consolidated operations and the distributed income from our equity method investee. For purposes of these calculations, “earnings” is the amount resulting from adding and subtracting the following items:

Add the following, as applicable:

- consolidated pre-tax income before parent interest in income of subsidiaries and income or loss from our equity investee;
- fixed charges;
- amortization of capitalized interest;
- distributed income of our equity investee; and
- our share of pre-tax losses of our equity investee for which charges arising from guarantees are included in fixed charges.

From the subtotal of the added items, subtract the following, as applicable:

- interest capitalized;
- preference security dividend requirements of consolidated subsidiaries; and
- parent interest in income of subsidiaries in pre-tax income of subsidiaries that have not incurred fixed charges.

The term “fixed charges” means the sum of the following: interest expensed and capitalized; amortized premiums, discounts and capitalized expenses related to indebtedness; an estimate of interest within rental expenses; and preference dividend requirements of consolidated subsidiaries.

Our ratio is significantly higher for the years ended December 31, 2006, 2005 and 2004 because we did not have any interest expense, capitalized interest or parent interest in income of subsidiaries expense.

Exhibit 21.1

LIST OF SUBSIDIARIES
DUNCAN ENERGY PARTNERS L.P.
as of February 2, 2009

Name of Subsidiary	Jurisdiction of Formation	Direct and Indirect Effective Ownership
Acadian Gas, LLC	Delaware	66%
Acadian Gas Pipeline System	Texas	100%
Calcasieu Gas Gathering System	Texas	100%
Cypress Gas Marketing, LLC	Delaware	100%
Cypress Gas Pipeline, LLC	Delaware	100%
DEP OLPGP, LLC	Delaware	100%
DEP Operating Partnership, L.P.	Delaware	100%
Enterprise Holding III, L.L.C.	Delaware	100%
Enterprise GC, L.P.	Delaware	66%
Enterprise Intrastate L.P.	Delaware	51%
Enterprise Texas Pipeline LLC	Texas	51% (1)
Enterprise Lou-Tex Propylene Pipeline L.P.	Delaware	66%
Evangeline Gulf Coast Gas, LLC	Delaware	100%
MCN Acadian Gas Pipeline, LLC	Delaware	100%
MCN Pelican Interstate Gas, LLC	Delaware	100%
Mont Belvieu Caverns, LLC	Delaware	66%
Neches Pipeline System	Texas	100%
Pontchartrain Natural Gas System	Texas	100%
Sabine Propylene Pipeline L.P.	Texas	66%
South Texas NGL Pipeline LLC	Delaware	66%
Tejas-Magnolia Energy, LLC	Delaware	100%
TXO-Acadian Gas Pipeline, LLC	Delaware	100%

(1) Reflects a 51% voting membership interest. The economic interest of this membership interest includes tiered preference distributions and priority returns.

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-149583 of Duncan Energy Partners L.P. on Form S-3 of our reports dated March 2, 2009 (which report expresses an unqualified opinion and includes an explanatory paragraph relating to the preparation of the financial statements of Duncan Energy Partners L.P. from the separate records maintained by Enterprise Products Partners L.P.), relating to the financial statements of Duncan Energy Partners L.P. and the effectiveness of Duncan Energy Partners L.P.'s internal control over financial reporting, appearing in this Annual Report on Form 10-K of Duncan Energy Partners L.P. for the year ended December 31, 2008.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
March 2, 2009

EXHIBIT 31.1

CERTIFICATIONS

I, Richard H. Bachmann, certify that:

1. I have reviewed this annual report on Form 10–K 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: March 2, 2009

/s/ Richard H. Bachmann

Name: Richard H. Bachmann
Title: Chief Executive Officer of DEP Holdings, LLC,
the General Partner of Duncan Energy Partners L.P.

EXHIBIT 31.2

CERTIFICATIONS

I, W. Randall Fowler, certify that:

1. I have reviewed this annual report on Form 10–K 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: March 2, 2009

/s/ W. Randall Fowler

Name: W. Randall Fowler
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 RICHARD H. BACHMANN, 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 for the year ended December 31, 2008 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Richard H. Bachmann, 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/ Richard H. Bachmann
Name:	Richard H. Bachmann
Title:	Chief Executive Officer of DEP Holdings, LLC, the General Partner of Duncan Energy Partners L.P.
Date:	March 2, 2009

EXHIBIT 32.2

SARBANES-OXLEY SECTION 906 CERTIFICATION

**CERTIFICATION OF W. RANDALL FOWLER, 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 for the year ended December 31, 2008 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, W. Randall Fowler, 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/ W. Randall Fowler
Name:	W. Randall Fowler
Title:	Chief Financial Officer of DEP Holdings, LLC, the General Partner of Duncan Energy Partners L.P.
Date:	March 2, 2009