

PARTNERSHIP PROFILE

Enterprise Products Partners L.P. is the largest publicly traded energy partnership and a leading North American provider of midstream energy services to producers and consumers of natural gas liquids ("NGLs"), crude oil, refined products and petrochemicals.

Services include:

- -- natural gas transportation, gathering, processing and storage;
- -- NGL fractionation, transportation, storage, and import and export terminaling;
- -- crude oil and refined products storage, transportation and terminaling;
- -- offshore production platform;
- -- petrochemical transportation and storage; and
- -- marine transportation.

FINANCIAL HIGHLIGHTS

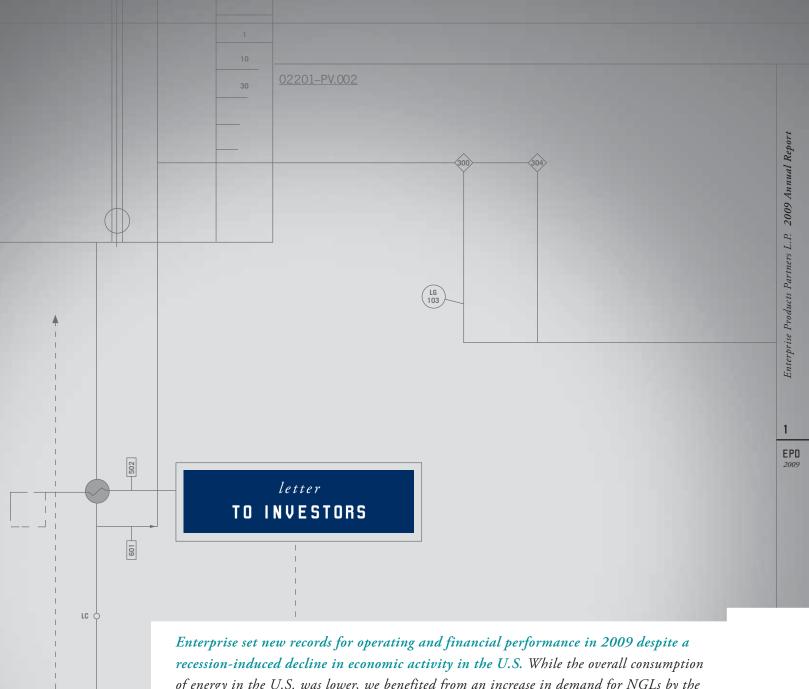
(Amounts in thousands except per unit amounts)	2009	2008	2007
INCOME STATEMENT DATA:			
Revenues from consolidated operations	\$ 25,511	\$ 35,470	\$ 26,714
Equity in income of unconsolidated affiliates	\$ 51	\$ 35	\$ 11
Gross operating margin ⁽¹⁾	\$ 2,840	\$ 2,609	\$ 1,964
Adjusted EBITDA ⁽²⁾	\$ 2,686	\$ 2,546	\$ 2,005
Operating income	\$ 1,824	\$ 1,748	\$ 1,195
Net income attributable to Enterprise	\$ 1,031	\$ 954	\$ 534
Fully diluted earnings per unit	\$ 1.73	\$ 1.84	\$ 0.95
Number of units for fully diluted calculation	487,869	437,582	434,427
BALANCE SHEET DATA:			
Total assets	\$ 26,152	\$ 24,212	\$ 22,516
Total debt	\$ 11,346	\$ 11,638	\$ 8,771
Noncontrolling interest (formerly Minority interest)	\$ 530	\$ 3,206	\$ 2,882
Total Enterprise Products Partners L.P. partners' equity	\$ 9,512	\$ 6,090	\$ 6,134
OTHER FINANCIAL DATA:			
Net capital expenditures	\$ 1,567	\$ 2,512	\$ 2,706
Business acquisitions, net of cash received	\$ 107	\$ 554	\$ 36
Investments in unconsolidated affiliates	\$ 19	\$ 65	\$ 237
Total	\$ 1,693	\$ 3,131	\$ 2,979
Distributable cash flow ⁽²⁾	\$ 1,643	\$ 1,378	\$ 1,001
Cash distributions declared per common unit ⁽³⁾	\$ 2.20	\$ 2.08	\$ 1.95
Annual cash distribution rate at December 31(3)	\$ 2.24	\$ 2.12	\$ 2.00

Note: Data is recast to include TEPPCO for all periods.

- See page 81 for a definition of gross operating margin and a reconciliation of this non-GAAP financial measure to its most directly comparable GAAP financial measure, operating income.
- (2) See page 110 for a reconciliation of non-GAAP Adjusted EBITDA and Distributable Cash Flow to their most directly comparable GAAP financial measures.
- (3) Cash distributions declared per common unit represent cash distributions declared with respect to the four fiscal quarters of each year presented. The annual cash distribution rate at December 31 is the quarterly rate declared for the fourth quarter annualized.







Enterprise set new records for operating and financial performance in 2009 despite a recession-induced decline in economic activity in the U.S. While the overall consumption of energy in the U.S. was lower, we benefited from an increase in demand for NGLs by the petrochemical and refining industries as feedstocks because of NGLs' global cost advantage relative to more expensive crude oil derivatives. We also completed construction of several growth capital projects that began generating new sources of cash flow.

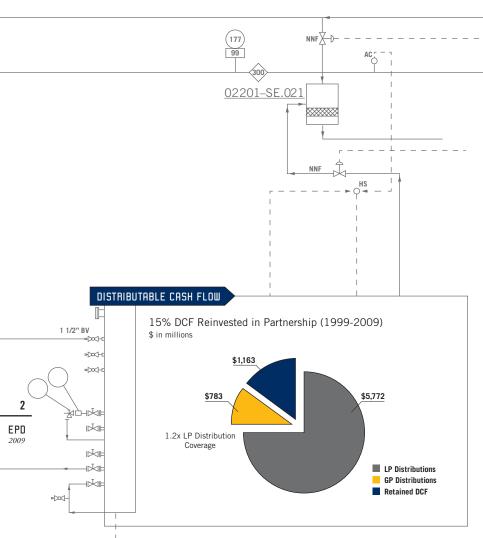
This record performance enabled us to achieve our goal of increasing Enterprise's cash distribution rate at the end of 2009 to an annualized \$2.24 per unit while retaining more than \$260 million of distributable cash flow to reinvest in the growth of the partnership. We also took proactive steps throughout 2009 to strengthen our liquidity and, with support from our debt and equity investors, demonstrated our ability to raise capital in difficult markets. As a result, our partnership began 2010 with a solid financial foundation and approximately \$2 billion of liquidity.

We broadened our midstream energy footprint in 2009 with the acquisition of TEPPCO Partners, L.P. This purchase provides us

new avenues of growth in the transportation and storage of refined products and crude oil. In addition, our assets continue to provide us with additional growth opportunities, such as the construction of natural gas pipelines to serve producers in the developing Haynesville and Eagle Ford Shale plays.

ANOTHER RECORD YEAR

In 2009, our system of midstream energy assets transported a record 4.0 million barrels per day ("BPD") of NGLs, crude oil, refined products and petrochemicals and 11.9 billion cubic feet per day ("Bcfd") of natural gas. The partnership increased its NGL fractionation volumes to a record 461,000 BPD; while our equity NGL production, the NGLs that Enterprise earns title to by



providing natural gas processing services, increased to a record 117,000 BPD. These record volumes led to a significant increase in gross operating margin and distributable cash flow. Gross operating margin for 2009 increased by 8.8 percent to a record \$2.8 billion.

The growth in gross operating margin was principally driven by our NGL Pipelines & Services segment, which generated a 23 percent increase in gross operating margin to a record \$1.6 billion. Overall, this segment benefited from the growth of natural gas volumes delivered to, and NGL volumes extracted by, our processing plants that flowed through our downstream NGL pipelines, fractionators, storage facilities and export terminal. Gross operating margin from the NGL segment was also supported by (1) attractive natural gas processing margins due to the increased demand for NGLs; (2) profits from hedging transactions related to approximately 70 percent of our 2009 equity NGL production that were executed in 2008; and (3) profits generated from our NGL marketing activities. To manage the value of our expected 2010 equity NGL production, we hedged approximately 53 percent of our estimated volumes by the end of April 2010 and we expect to hedge more of these volumes over the coming months.

Distributable cash flow for 2009 increased 19 percent to a record \$1.6 billion. This growth supported increases in each of our distributions to unitholders during the year. Our distributions declared with respect to 2009 increased 5.8 percent to \$2.195 per unit from \$2.075 per unit in 2008. In addition, Enterprise retained \$264 million, or 16 percent, of distributable cash flow.

Our fundamental objectives are the same today as they were at the time of our initial public offering in 1998:

- -- to invest in growth opportunities to build or acquire energy infrastructure that will generate returns on investment greater than our long-term cash cost of capital in order to create economic value for Enterprise and our partners;
- to provide our partners with periodic increases in cash distributions and an attractive total return on their investment; and
- -- to preserve our financial flexibility and to maintain an investment-grade balance sheet as we pursue our goals.

We have a history of balancing distribution growth with the retention of distributable cash flow. Since 1998, Enterprise has generated \$7.7 billion of distributable cash flow. The partnership has paid aggregate distributions of \$5.8 billion to our limited partners over 46 consecutive quarters. We have increased the distribution rate 31 times by a total of 149 percent, including distribution increases in each of the last 22 consecutive quarters. We have also retained approximately \$1.2 billion, or 15 percent, of Enterprise's distributable cash flow. We have used this retained capital to invest in growth projects, to retire debt, to limit the need to issue new equity, as well as to insulate our partners from earnings variability in some of our businesses. Successfully executing on this formula has enabled us to provide our limited partners with a total return, including reinvested distributions, of 830 percent since the beginning of 1999.

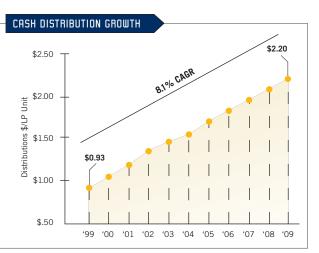


LOWER COST OF CAPITAL MAKES A DIFFERENCE

Part of Enterprise's success is our lower cost of capital.

This is largely attributable to the foresight of our general partner in 2002 to eliminate the 50-percent tier of its incentive distribution rights, thereby capping these rights at 25 percent.

This single action has saved Enterprise approximately \$600 million in aggregate distributions that would have otherwise been paid to our general partner without Enterprise receiving any economic value in return. Based on our current annualized cash distribution rate of \$2.24 per unit, Enterprise is saving \$278 million per year in avoided distributions to the general partner, which is equivalent to approximately \$0.45 per unit of limited partner distributions. This additional financial flexibility enables us to retain more distributable



cash flow as we increase our cash distribution rate and allows us to generate more distributable cash flow accretion from investments in new assets and acquisitions. Some publicly traded partnerships, as well as certain equity analysts and investors, are beginning to recognize the challenges to partnership growth caused by the higher cost of capital associated with a general partner's 50-percent incentive distribution rights.

PUTTING NEW ASSETS TO WORK

In 2009 and thus far in 2010, we have completed \$1.8 billion of new capital projects, including projects serving the prolific Piceance Basin in Colorado and Barnett Shale region in Texas. These projects include a 750 million cubic feet per day ("MMcf/d") expansion of our Meeker natural gas processing plant; a central treating facility and supporting pipeline infrastructure that is contracted to ExxonMobil; and two natural gas gathering pipelines

to serve other large producers in the basin. These two gathering systems supply additional volumes of natural gas to our Piceance Basin pipeline system and Meeker plant. NGLs extracted at the Meeker facility flow through our integrated system of downstream NGL pipeline, fractionator and storage assets.

We also completed the Sherman Extension expansion of our Texas Intrastate natural gas pipeline system. This 1.1 billion cubic feet per day ("Bcf/d") pipeline serves producers in the Barnett Shale area of North Texas. The Sherman Extension began full commercial service in August 2009. We expect to complete our Trinity River Basin pipeline project, which is a lateral that connects new areas of natural gas production in the Barnett Shale with the Sherman Extension, in the third quarter of 2010.

Our Shenzi crude oil pipeline in the Gulf of Mexico commenced operations in the second quarter of 2009 and has exceeded our expectations. Volumes transported on Shenzi flow into our downstream Cameron Highway and Poseidon crude oil pipelines, which deliver crude oil to onshore markets in Texas and Louisiana. In addition, we are nearing completion of a 5.4 million barrel refined products storage facility that is under long-term contract with Motiva to serve its Port Arthur, Texas refinery expansion.

BROADENING OUR FOOTPRINT

Enterprise significantly broadened its midstream energy footprint in 2009. The largest component of this expansion was the acquisition of TEPPCO Partners, L.P. valued at \$6.1 billion, the largest acquisition of a publicly traded energy partnership.

This transaction established Enterprise as the largest publicly traded energy partnership in terms of our \$31 billion enterprise value, and as one of the largest midstream energy companies with over 48,000 miles of natural gas, NGL, crude oil and refined products pipelines.

In addition to broadening our array services to include onshore crude oil and refined products logistical services, we also acquired a major NGL pipeline serving markets in the Midwest and Northeast: the Enterprise TE Products Pipeline. This pipeline bisects the developing Marcellus Shale natural gas play in Pennsylvania and Ohio. In the same way that the acquisition of the Mid-America Pipeline ("MAPL") in 2002 provided Enterprise with an initial foothold to extend our midstream value chain into the growing Jonah/Pinedale and Piceance Basin regions in the Rocky Mountains, the Enterprise TE Products Pipeline now provides us with a base from which we could potentially extend our system into the Marcellus Shale region.

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Our management team has done a remarkable job in quickly absorbing the TEPPCO businesses. In this short period of time, we have already identified a number of opportunities to either increase revenues or reduce expenses, which in total are expected to increase distributable cash flow by approximately \$35 million. This is in addition to the approximately \$20 million in annual cost savings that we originally forecasted. We are already beginning to see some of these benefits in 2010. We believe the TEPPCO assets will provide additional expansion projects as we seek to expand their scope and scale.

Enterprise's large geographic footprint continues to provide new growth opportunities. Our most recent organic growth projects are to serve the developing Haynesville Shale and Eagle Ford Shale natural gas plays. We have entered into longterm agreements with producers supporting an expansion of our Louisiana intrastate natural gas pipeline system to serve the Haynesville Shale area of Northwest Louisiana. Our 270-mile Haynesville Extension pipeline will have the capacity to transport up to 2.1 Bcf/d of natural gas. The partnership's natural gas, NGL and crude oil assets in South Texas are well-positioned to benefit from the development of the Eagle Ford Shale. To date, we have made nominal capital investments to bring this production into our system. Given the success and the acceleration of drilling plans by producers in the Eagle Ford, we are evaluating larger projects to expand our natural gas, NGL and crude oil infrastructure in South Texas.

We believe the most important attribute of a successful midstream energy company is connecting large, long-life producing areas of natural gas, NGLs, crude oil and condensate with the major markets for these hydrocarbons. Enterprise's integrated network of midstream energy assets is one of the best in the industry. We serve the largest producing regions in the lower 48 states, including some of the lowest-cost producing areas for NGL-rich natural gas.

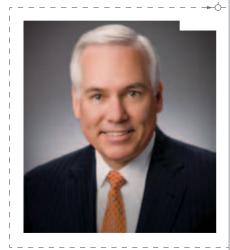
On the consuming end, we serve the Texas and Louisiana natural gas and NGL markets, which are the largest in the U.S. Our NGL pipelines access petrochemical production facilities that represent virtually all U.S. ethylene production capacity and refineries that represent approximately 90 percent of the motor gasoline refining capacity east of the Rockies. We believe our system will continue to generate new growth opportunities.

On behalf of the Enterprise family, I would like to thank the financial community and the general public for their condolences and show of support following the recent and unexpected passing of our chairman and founder, Dan Duncan. While he will certainly be missed, during his lifetime, Dan carefully planned to ensure that the partnership would be positioned for continued growth and success following his death. In terms of succession, his intentions were for Enterprise to be run by a professional management team with significant experience in the midstream energy industry and an in-depth knowledge of our assets. The strong team that has been assembled at Enterprise is a testament to the fulfillment of those intentions. To help maintain management continuity, Dan's indirect control of Enterprise Products Partners, Duncan Energy Partners and Enterprise GP Holdings has been assumed by a voting trust comprised of one of his daughters and two long-time family advisors, both of whom hold executive and director positions on the boards of the various Enterprise family of partnerships.

In closing, we would like to recognize our employees for their dedication and hard work in safely operating our assets and providing exceptional service to our customers. We would also like to thank our debt investors and equity partners for their continuing support, which enabled us to raise over \$2.5 billion of capital in the sometimes turbulent markets of 2009. We are counting on your continued support in 2010.

Michael A. Creel

President and Chief Executive Officer



Dan L. Duncan TRIBUTE



1933-2010

Dan L. Duncan, who co-founded Enterprise Products Company more than 40 years ago and turned a small operation consisting of two propane delivery trucks into the largest publicly traded energy partnership, passed away unexpectedly on March 29, 2010 at his home in Houston. While saddened by the loss, the Enterprise family is also grateful for his legacy of accomplishment, visionary leadership and personal integrity, which will continue to serve as the foundation for the continued success of the partnership.

His rags-to-riches story, which began January 2, 1933 in rural Shelby County, Texas, is well documented, but remains an inspiring example of the American Dream and a testament to the value of hard work, perseverance and optimism in the face of adversity. At the age of seven, he lost his mother to tuberculosis and his older brother died of blood poisoning after cutting himself on a rusty can; both events occurred within three months of each other. At the age of 18, Mr. Duncan's father passed away from leukemia.

For much of his upbringing, Mr. Duncan lived with his grandmother, who instilled within him a strong work ethic.

Drawing from her wisdom, which was summed up in the simple message she repeated to him, "Do the best you can every day,"

Mr. Duncan not only persevered through these early tragic events but flourished.

After graduating from high school, Mr. Duncan followed in his father's footsteps and began working as a pipeliner and roughneck. In 1953, he joined the U.S. Army during the Korean War. After his military service, he studied business, finance and accounting at Massey Business College in Houston, while working for the Postal Service under the G.I. Bill. His energy career began in earnest in 1957 when he joined Wanda Petroleum. Armed with the knowledge and experience he gained during his 11 years at Wanda, \$10,000 in capital and plans to make it big in the midstream business, Mr. Duncan helped establish Enterprise Products Company in 1968. In July 1998, Enterprise Products Partners L.P. completed its initial public offering with assets totaling a little more than \$700 million.

Under his leadership, Enterprise has grown to become one of the premier midstream energy companies in North America

with three publicly traded partnership affiliates having a combined market capitalization of approximately \$30 billion. In the process, Enterprise has become a Fortune 100 company that is consistently ranked among the nation's best-managed organizations. During that time, Mr. Duncan has firmly secured his place as a true pioneer in the energy industry whose groundbreaking efforts have transformed the midstream sector. Some of the more notable innovations for which he will be remembered include:

- -- Becoming the first MLP to cap the general partner's incentive distribution rights (IDRs) at 25 percent, compared to 50 percent that continues to be the standard for most of Enterprise's peers; lowering the IDRs reduces the partnership's cost of capital and gives it a strategic advantage in pursuing growth opportunities;
- Retaining distributable cash flow while continuing to grow distributions to partners as a way to fund capital expenditures and reduce debt;
- Entering into transactions that create win-win outcomes for both the customer and Enterprise, as well as foster long-term, mutually beneficial relationships;
- -- Developing the integrated value chain concept, which leverages Enterprise's comprehensive network of interconnected assets to provide value-added services for customers and multiple revenue-generating opportunities from the same molecule of energy for the partnership; and
- Building larger, expandable infrastructure in key producing and consuming areas that serve as hubs for providing midstream services and access to third-party systems.

An award-winning, international big-game hunter, Mr. Duncan was also a dedicated conservationist. Each year he hosted groups of underprivileged youth and handicapped children at his central Texas ranch for a weekend event, during which he helped pass along the importance of protecting natural resources and wildlife habitat to new generations. In honor of the brave service men and women of the armed forces who were severely injured in battle, Mr. Duncan hosted hunts at the ranch for members of the Wounded Warrior Project.

While Mr. Duncan's contributions to the business world are unparalleled, perhaps his most enduring legacy will be as one of America's most generous philanthropists, especially in the area of medical research and patient care. Over the past six years, he donated more than \$250 million to the Baylor College of Medicine, Texas Children's Hospital, the University of Texas Health Science Center at Houston, and M.D. Anderson Cancer Center. Thanks to his gifts, current and future generations of cancer patients, as well as children with neurological disorders and learning differences, will have the opportunity to lead longer, healthier and more productive lives.

Mr. Duncan is survived by his wife, Jan, four children, four grandchildren, as well as numerous extended family and friends.

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CONSERVATIONIST

Mr. Duncan's tireless support of efforts that promote conservation of wildlife habitat and natural resources, reflected his deep respect for the land, its inhabitants and their culture.

IPO ANNIVERSARY

To mark the 10th anniversary of EPD's initial public offering, Mr. Duncan and members of the executive management team and board of directors performed the closing bell honors at the New York Stock Exchange on July 29, 2008.

NGL PIPELINES & SERVICES

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With an asset base that includes 25 natural gas processing facilities, more than 16,000 miles of NGL pipelines, 163 million barrels of NGL storage, an NGL import/export terminal and 11 NGL fractionation facilities, Enterprise's NGL Pipelines & Services business segment represents North America's only fully integrated NGL network.



The services provided by this comprehensive midstream network link the most abundant sources of domestic NGLs with the most attractive consuming markets. Ethane, propane, normal butane, isobutane and natural gasoline are NGL products used as raw materials by the petrochemical industry and as feedstocks by refiners in the production of motor gasoline and by industrial and residential users as fuel.

Extracting mixed NGLs from the natural gas stream (i.e. natural gas processing) is the first step in the NGL value chain. Enterprise has facilities strategically located to serve producers in key producing basins, including the Piceance, Greater Green River, San Juan and Permian, as well as the emerging Eagle Ford Shale in South Texas.

Through its NGL pipeline network, Enterprise transports mixed NGLs to fractionators; distributes and receives NGL products between petrochemical plants and refineries; and delivers purity products, such as propane, to end users in the Midwest,

Southeast, Northeast and along the East Coast. The partnership's NGL pipelines connect to all of the country's ethylene steam cracking facilities and more than 90 percent of the domestic refinery market east of the Rockies.

Anchored by its Mont Belvieu, Texas complex, Enterprise's fractionation facilities, which feature net capacity of 529,000 BPD, separate NGLs into constituent parts: ethane, propane, butanes and natural gasoline, which typically have greater economic value as raw materials and feedstocks. With its Hobbs fractionator strategically positioned at the junction of the MAPL and Seminole pipelines, combined with the partnership's Mont Belvieu facility, the world's largest NGL trading hub, Enterprise offers customers the flexibility to access the most attractive markets, thereby maximizing the value of their product. The partnership's 163 million barrels of NGL storage, including over 100 million barrels at Mont Belvieu, provide customers with value-added services.



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MONT BELVIEU COMPLEX

In the shadow of existing fractionation towers at Enterprise's Mont Belvieu complex, the partnership is constructing a new 75,000 barrel per day NGL separation facility modeled after its Hobbs fractionator (below).



HOBBS FRACTIONATOR

ACCOMPLISHMENTS

During 2009 and continuing into 2010, Enterprise has benefited from the increased demand for NGLs over crude oil-derived feedstocks by the petrochemical industry. A surge in the number of facilities being modified to accept NGL feedstocks, driven primarily by lower natural gas prices relative to crude oil, has increased ethane cracking capacity by approximately 100,000 BPD.

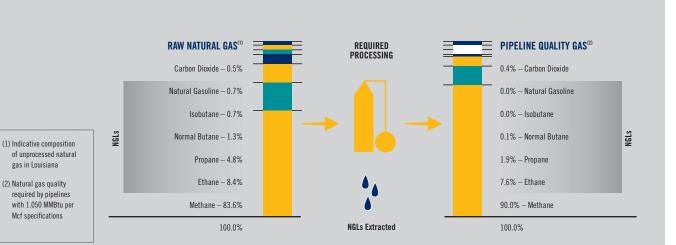
In August 2009, Enterprise announced plans to build a new 75,000 BPD NGL fractionator at Mont Belvieu. Supported by long-term contracts, this additional capacity will give the partnership the ability to accommodate growing NGL volumes from producing areas in the Rockies, the Barnett Shale and the emerging Eagle Ford Shale play in South Texas. The expansion is expected to be completed in the first quarter of 2011. Since 2006, Enterprise's NGL fractionation volumes have increased 47 percent to a record 477,000 BPD in the fourth quarter of 2009. Its fractionators are operating at or near practical limits, and the partnership has consistently contracted for additional capacity with third parties.

Expansion projects at two existing South Texas natural gas processing facilities in 2009, have allowed the partnership to accommodate increased production from the Eagle Ford Shale, which will have access to the new fractionator at Mont Belvieu. Modifications at the Shilling plant in Webb County increased capacity by 83 percent to 110 MMcf/d, while re-piping at the Thompsonville facility in Jim Hogg County improved capacity by 10 percent, to 330 MMcf/d.

During 2009, Enterprise completed construction of a new pipeline connecting a relocated processing plant to the Chaparral Pipeline, which provided a new source of NGLs into Mont Belvieu. The project also offered shippers access to major interstate natural gas transmission systems that provided access to markets in the western United States. Initiatives like the South Texas and Chaparral projects reflect Enterprise's successful strategy of leveraging existing assets and equipment to make minimal capital investments while generating attractive returns.

In the first quarter of 2009, Enterprise commenced Phase II operations at its Meeker processing complex, the centerpiece of its Piceance Basin midstream infrastructure. The expansion more than doubled natural gas processing capacity of the complex to 1.7 Bcf/d and increased Meeker's NGL extraction rates to 70,000 BPD.

NATURAL GAS PROCESSING DIAGRAM



Enterprise's NGL marketing business generates revenues from the sale and delivery of NGLs obtained through the partnership's processing activities and purchases from third parties on the open market. In support of Enterprise's commercial goals, its NGL marketing activities rely on inventories of mixed NGLs and purity NGL products. Strong energy market conditions in 2009 led to increased physical inventory purchases and related forward physical sales commitments compared to 2008.

2009 PERFORMANCE

gas in Louisiana

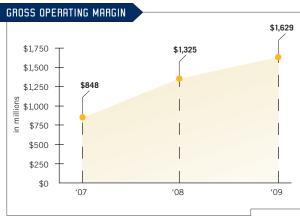
(2) Natural gas quality required by pipelines with 1.050 MMBtu per

Mcf specifications

NGL Pipelines & Services reported gross operating margin of \$1.6 billion in 2009, a 23 percent increase from \$1.3 billion of gross operating margin reported in 2008. This segment accounted for approximately 57 percent of the partnership's total gross operating margin in 2009.

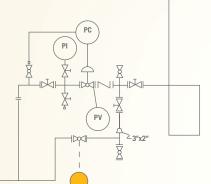
The natural gas processing and NGL marketing business recorded gross operating margin of \$949 million in 2009, a 16 percent increase compared to \$815 million in 2008. The recently completed Meeker and Pioneer processing facilities and related hedging program were responsible for \$105 million of the year-to-year increase in gross operating margin due to higher volumes and improved processing margins.

Gross operating margin from Enterprise's NGL pipelines and related storage business increased 36 percent to \$540 million in 2009, from \$397 million reported in 2008. Approximately \$86 million of the year-to-year increase was generated from the MAPL and Seminole pipeline systems, which benefited from a system-wide tariff increase, higher volumes and lower fuel costs, as well as a \$26 million benefit in 2009 related to the MAPL



system rate case settlement. NGL transportation volumes in 2009 averaged about 2.2 million BPD, an increase of more than 8 percent compared to an average of 2.0 million barrels per day in 2008.

The partnership's NGL fractionation business reported \$136 million of gross operating margin in 2009, up nearly 23 percent from the \$111 million recorded in 2008. The improvement in gross operating margin was primarily due to lower fuel costs and higher NGL fractionation volumes.



TRINITY RIVER LATERAL

Supported by long-term agreements, the Trinity River Lateral will be instrumental in supplying the Sherman Extension pipeline with natural gas from new producing areas of the Barnett Shale, such as the Newark East Field in

NATURAL GAS PIPELINES



Enterprise's Onshore Natural Gas Pipelines & Services business segment is comprised of approximately 19,200 miles of natural gas pipelines and 27 Bcf of underground storage capacity. Enterprise handles nearly 20 percent of the United States' daily demand for natural gas.

The partnership's network of onshore natural gas pipelines serves producers in some of the most prolific natural gas producing regions in the U.S. This includes both the established conventional basins and the developing unconventional and shale natural gas plays such as the Jonah/Pinedale field, the Piceance Basin, the San Juan Basin, the Barnett Shale, the Eagle Ford Shale and the Haynesville Shale.

Enterprise's pipelines link raw natural gas production to its natural gas processing facilities that extract NGLs and impurities to enable end-use consumption. Downstream of its processing plants, Enterprise's pipelines transport processed natural gas to industrial end users, local distribution companies, power generators and other pipeline systems that provide access to end-use markets.

ACCOMPLISHMENTS

In the Greater Green River Basin of Southwest Wyoming, Enterprise completed an expansion of the Jonah Gas Gathering system, increasing capacity to 2.6 Bcf/d. This system serves producers in the prolific unconventional Jonah and Pinedale fields. Since 2004, volumes on this system have more than doubled from 0.9 Bcf/d to 2.4 Bcf/d in 2009. The Jonah Gas Gathering system is the source of natural gas processed by Enterprise's Pioneer cryogenic processing plant. Areas of the Jonah and Pinedale fields dedicated to the partnership's Jonah Gas Gathering system are estimated to have 9 trillion cubic feet of proved reserves and 16 years of drilling locations.

In the Piceance Basin, Enterprise completed several pipeline projects that led to an 89 percent increase in total volumes

RRMSTRONG | Expansion projects, including one currently under way at the partnership's Armstrong fractionation facility, will give Enterprise the opportunity to leverage its existing South Texas assets by investing minimal amounts of capital to significantly increase its ability to accommodate volumes from the Eagle Ford Shale.

handled by its Piceance Basin pipeline system and related White River Hub in 2009 compared to 2008. Natural gas transported on the partnership's Piceance Basin pipeline is processed by its Meeker facility. The White River Hub, a joint venture between Enterprise and Questar Corporation, provides producers with flexibility to access the highest-value markets through connections with six interstate pipelines that reach markets as far away as California to the west and Ohio to the east.

In August 2009, full operations began on the 173-mile Sherman Extension expansion of Enterprise's Texas Intrastate natural gas pipeline system. The Sherman Extension runs through the heart of the Barnett Shale region and provides 1.2 Bcf/d of natural gas takeaway capacity. To accommodate increasing production in new areas near the Dallas/Fort Worth metroplex, Enterprise is constructing a 40-mile, 1 Bcf/d supply lateral from the Trinity River Basin to an interconnect on the Sherman Extension. Both the Sherman Extension and Trinity River Lateral are supported by long-term transportation contracts. The Trinity River Lateral is expected to begin full operations in the third quarter 2010.

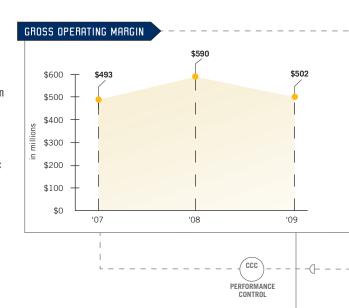
In South Texas, Enterprise is leveraging its existing asset position to become the preferred provider of comprehensive midstream services to producers in the emerging Eagle Ford Shale. Natural gas produced from the Eagle Ford Shale runs the spectrum from lean to very rich—up to nine gallons of NGLs per thousand cubic feet (Mcf) of natural gas. More than just a natural gas play, areas of the Eagle Ford Shale also produce crude oil. Enterprise has natural gas, NGL and crude oil infrastructure adjacent to areas where the Eagle Ford Shale is currently being developed. The partnership's integrated system will enable producers to earn the highest value for their production.

Enterprise's ability to incrementally expand infrastructure quickly and cost efficiently gives the partnership an important competitive advantage. The partnership has completed a number of small pipeline projects that add an estimated 300 MMcf/d of

incremental natural gas transportation capacity for Eagle Ford Shale production. These incremental natural gas volumes will be processed at Enterprise's plants in the region. In turn, the extracted NGLs will enter Enterprise's downstream NGL pipeline, fractionation and storage systems. Enterprise also plans to expand its network of crude oil pipelines in the Eagle Ford Shale region to serve the expected increase in production.

In October 2009, Enterprise announced the Haynesville Extension Pipeline. The Haynesville Extension is a 270-mile pipeline that extends the partnership's Acadian intrastate natural gas pipeline system in southern Louisiana into the rapidly expanding Haynesville Shale area in Northwest Louisiana. The extension is designed to transport up to 2.1 Bcf/d of natural gas and is supported by long-term agreements. Following completion of the project, which is expected in the third quarter of 2011, shippers will have access to nine major interstate pipelines and more than 150 end-use markets along the Mississippi River corridor in South Louisiana.

The project is designed to give shippers another option to the congested Perryville Hub market. Additionally, the Haynesville Extension will give shippers the opportunity to make deliveries to Henry Hub, the physical clearing location for natural gas futures contracts traded on the New York Mercantile Exchange, and to storage facilities. Certain industry sources have forecasted that the Haynesville Shale has the potential to cover two million acres and become the fourth-largest natural gas field in the world with up to 200 trillion cubic feet of natural gas reserves.



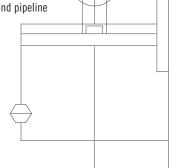
In April 2010, Enterprise announced the execution of definitive agreements to purchase two natural gas gathering and treating systems located in Northwest Louisiana and East Texas, which gather natural gas produced from the Haynesville/Bossier Shale play and the Cotton Valley and Taylor Sands formations. These systems are supported by long-term acreage dedications and volumetric commitments from producers. One of the systems to be acquired will interconnect with Enterprise's Haynesville Extension Pipeline, which accelerates the partnership's entry into the Haynesville/Bossier Shale play and substantially increases its footprint in the area. Expected to close in early May 2010, completion of the transaction is subject to customary regulatory approvals, including those under the Hart-Scott-Rodino Antitrust Improvements Act, and other customary closing conditions.

2009 PERFORMANCE

This business segment generated \$502 million of gross operating margin in 2009, or approximately 18 percent of Enterprise's total gross operating margin. Enterprise's onshore natural gas

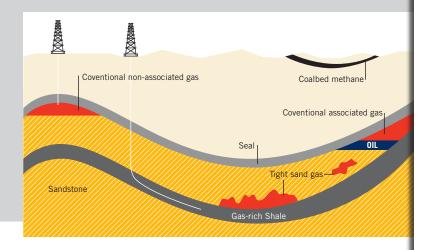
pipelines transported 10.4 trillion British thermal units per day ("Btus/d") of natural gas during 2009, a 9 percent increase from 2008. Volume growth was largely attributable to Enterprise's assets in the Rocky Mountains: the Jonah and Piceance Basin pipelines and the White River Hub.

Gross operating margin in 2009 decreased approximately \$88 million from 2008 primarily due to lower gathering fees collected on the San Juan system. Fees on a significant amount of natural gas gathered on this system are indexed to regional natural gas prices, which were significantly lower in 2009 compared to 2008. Overall, Enterprise has a natural hedge to changes in natural gas prices. While the San Juan system was adversely impacted by lower natural gas prices, this was largely offset by lower fuel costs at many of the partnership's other assets, such as NGL and propylene fractionators and pipeline compressor and pump stations.



CONVENTIONAL — UNCONVENTIONAL NATURAL GAS COMPARISON

Breakthroughs in technology have accelerated development of unconventional natural gas plays so significantly that they now comprise more than half of the U.S. gas market account for almost all of the growth in domestic gas resources over the past five years. Just over 10 percent of the nation's supplies of natural gas now originate from shale gas plays, nearly two-thirds of which comes from the Barnett Shale. To fully appreciate the shift that has occurred within the industry requires an understanding of how unconventional development differs from conventional methods.



CONVENTIONAL

- Traditional geologic structure comprised of: 1) source rock;
 2) source rock with organic matter that has generated hydrocarbons in sufficient volumes;
 3) a reservoir in which migrating hydrocarbons can accumulate;
 and 4) a trap;
- -- Typically focused on plays with greater exploratory risk, but higher payout per well;
- -- Utilization of proven, well-established drilling and completion techniques; and
- -- Well-defined reservoir means fewer wells needed to develop reserves.

UNCONVENTIONAL

- -- Includes shale gas, tight gas sands and coalbed methane plays;
- -- Greater certainty of finding reserves;
- -- Production zones in multiple, horizontal layers;
- -- Requires non-traditional drilling and completion techniques, such as fracturing and horizontal drilling;
- -- More wells required to develop producing area, compared to conventional reservoir; and
- -- Number of unconventional natural gas plays continuing to emerge and mature throughout the U.S.

SHENZI

With a capacity of 230,000 BPD of crude oil, the Shenzi Pipeline was built with excess capacity and additional interconnects, giving Enterprise the flexibility to add other shippers in the growing Green Canyon area and Lower Tertiary play in the Gulf of Mexico.



The Offshore Pipelines & Services segment, which includes approximately 2,400 miles of natural gas and crude oil pipelines and six multi-purpose hub platforms, is well-positioned to serve some of the most active and growing production areas in the Gulf of Mexico.

HUB PLATFORMS

NATURAL GAS

CRUDE OIL PIPELINES

The partnership's offshore network of more than 1,400 miles of interconnected natural gas pipelines provides gathering and transmission services for producers, primarily off the coasts of Texas and Louisiana, and receives deliveries through interconnects with other offshore pipelines. Through this network of pipelines, Enterprise is able to provide access to major onshore interstate pipelines that reach consuming markets in the eastern half of the United States. A significant piece of this infrastructure is the partnership's Independence Trail pipeline, which links its Independence Hub, the world's deepest platform, to onshore markets and has the capacity to move 1 Bcf/d of natural gas. Net capacity on Enterprise's offshore natural gas pipelines is more than 6 Bcf/d.

Enterprise has approximately 1,000 miles of offshore crude oil pipelines that serve major crude oil producing areas in the Gulf of Mexico and provide shippers with flexibility to maximize the value of their production. In addition to direct connections with producing wells, the partnership's crude oil pipelines also receive volumes from other pipelines for delivery to onshore locations or offshore interconnecting systems. The partnership's offshore crude oil pipelines have a combined net capacity of more than 1 million BPD.

Enterprise's Cameron Highway Offshore System (CHOPS), which gathers crude oil from the Southern Green Canyon area and other deepwater regions of the Gulf of Mexico, is an especially

INDEPENDENCE HUB PLATFORM

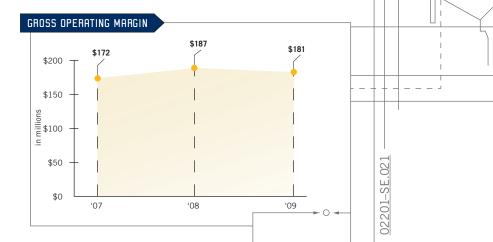


important link in the supply chain for refiners along the Texas Gulf Coast. Complementing CHOPS is the Poseidon Pipeline, which delivers crude oil from the deepwater and shallower areas of the Gulf of Mexico to facilities in Louisiana.

Enterprise's offshore platforms play an important role in supporting its pipeline network, and are vital to development of oil and gas reserves in the Gulf of Mexico. These facilities are used to link pipeline systems together, perform maintenance, house compression and production equipment, conduct drilling operations and process production from third-party wells. The record-setting Independence Hub reflects Enterprise's strategy of recognizing the potential of promising producing areas and investing the financial and creative capital to develop effective midstream solutions. With the capability to process up to 1 Bcf/d of natural gas, the Independence Hub can accommodate more than 12 percent of daily production from the Gulf of Mexico.

ACCOMPLISHMENTS

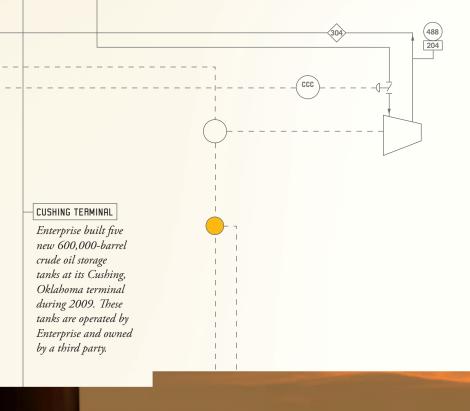
In April of 2009, Enterprise began transporting crude oil through its new Shenzi Pipeline located at a depth of 4,300 feet in the deepwater Gulf of Mexico. The 83-mile, 20-inch diameter pipeline, which was completed ahead of schedule and under budget, serves the BHP Billiton-operated Shenzi Field at Green Canyon Block 653. The pipeline provides access to Enterprise's CHOPS and Poseidon pipeline systems.



2009 PERFORMANCE

Gross operating margin for the Offshore Pipelines and Services segment in 2009 was \$181 million compared to \$187 million in 2008, reflecting the effects of Hurricane Ike and repairs to the Independence Hub in 2009. One-time charges recorded during 2009 associated with the partnership's exit from the Texas Offshore Port System partnership were offset by year-over-year improvements in gross operating margin from Enterprise's offshore natural gas and crude oil pipeline businesses.

During 2009, volumes on the partnership's offshore crude oil pipelines increased to an average of 308,000 BPD compared to an average of 169,000 BPD during 2008, as a result of the Shenzi pipeline being brought into service. Volumes on Enterprise's offshore natural gas pipelines increased from 1.41 trillion Btus/d in 2008 to 1.42 trillion Btus/d in 2009. Natural gas processing volumes on the partnership's platforms averaged 700 MMcf/d during 2009, a more than 10 percent increase from an average of 632 MMcf/d during 2008. Platform crude oil processing averaged 12,000 BPD during 2009 compared to an average of 15,000 BPD during 2008.





CRUDE OIL PIPELINES

Through its extensive network of pipelines and storage facilities, Enterprise's Onshore Crude Oil Pipelines & Services business segment provides gathering, transportation, storage and marketing services that offer shippers enhanced flexibility to maximize the value of their crude oil.

The partnership's 4,400 miles of pipeline systems aggregate crude oil supplies from key producing areas in Texas, New Mexico and Oklahoma for delivery to refineries, third-party pipeline systems and storage facilities, including those at Cushing, Oklahoma, which serves as a NYMEX pricing point.

Access to Cushing is also provided by the Enterprise-operated Seaway Crude Oil Pipeline System, a 530-mile artery that originates in Freeport, Texas and has the capacity to transport approximately 340,000 BPD of crude oil from both onshore and offshore receipt points. The Seaway pipeline connects to refineries in the Houston, Texas area through its terminal facility at Texas City, Texas and receives crude oil production from the Texas Gulf

Coast area through its connection to the partnership's South Texas System.

At its Cushing Terminal, Enterprise owns 19 storage tanks with an aggregate crude oil storage capacity of 3.1 million barrels ("MMBbls"). In 2009, Enterprise constructed five, third-party storage tanks that provide an incremental 3.0 MMBbls of crude oil storage capacity. Enterprise earns fees for providing storage and other terminaling services. Enterprise also earns fees to operate storage tanks owned by others. The stability of fee-based income helps limit Enterprise's exposure to swings in commodity prices, whereas ownership of crude oil storage capacity supports its marketing objectives, allowing it to

capitalize on opportunities that offer attractive returns with minimal risk. Combined, Enterprise owns a network of crude oil storage tanks having more than 10 MMBbls of capacity.

Impacted by general economic conditions and conservation by consumers, U.S. demand for petroleum products, including crude oil, decreased approximately 5.4 percent during the first 10 months of 2009 from the same period in 2008, as reported by the U.S. Energy Information Administration. However, since mid-2009 the rate of decline in U.S. demand for petroleum products appears to be moderating and the price of crude oil has rebounded with the recovery in demand and economic growth. The average price for West Texas Intermediate crude oil has increased by approximately 82 percent from December 2008 to December 2009. Crude oil production is expected to increase after experiencing a 2.2 MMBbl/d reduction in 2009. The Organization of Petroleum Exporting Countries is expected to increase its production of crude oil by an average of 400,000 BPD in 2010 and 2011 to satisfy a projected rise in global demand for crude oil.

ACCOMPLISHMENTS

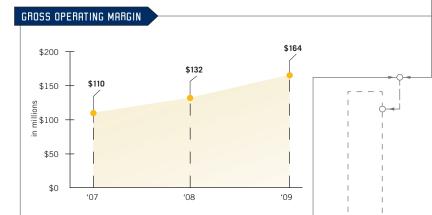
Texas market.

is expected to play an increasingly important role in Enterprise's development plans for the Eagle Ford Shale play in South Texas. Generally, energy companies have had early success in the Eagle Ford Shale and several have indicated plans to accelerate their drilling programs. Production associated with this region includes crude oil, as well as natural gas. Currently, the partnership provides transportation services by truck for growing crude oil and condensate production from the Eagle Ford Shale; however, there may also be opportunities for investing capital to expand its crude oil pipeline and storage facilities. Enterprise is also evaluating logistics opportunities that would enable Eagle Ford Shale crude oil and condensate production to be marketed

As a result of the projected increase in crude oil demand, the Onshore Crude Oil Pipelines & Services business segment

In 2009, Enterprise increased storage capacity at its Cushing, Oklahoma terminal. Operated by Enterprise for a third party, the additional infrastructure satisfies increased demand for storage as customers look to benefit from contango market conditions.

at either the Cushing, Oklahoma oil trading hub or the Houston,



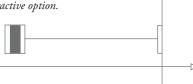
2009 PERFORMANCE

Gross operating margin for this segment was \$164 million in 2009, a 24 percent increase from \$132 million reported in 2008. The improvement was primarily due to increased sales volumes and margins related to Enterprise's crude oil marketing activities. Crude oil transportation volumes were 680,000 BPD in 2009 compared to 696,000 BPD reported in 2008.



SERWAY TERMINAL

The strategic importance of the Enterprise-operated Seaway Terminal and associated 30-inch diameter mainline was underscored in 2009 as shippers looking to capitalize on strong storage fundamentals found the direct access to Cushing offered by the system to be an attractive option.





PORT ARTHUR STORAGE

In addition to supporting Motiva's refinery expansion, Enterprise has identified other opportunities to put its new Port Arthur storage facility and existing pipelines acquired from TEPPCO to work and generate additional sources of income.



Enterprise's Petrochemical & Refined Products Services business segment includes assets designed to ensure reliable supplies of feedstocks for major refiners and petrochemical plants along the Gulf Coast, as well as refined products and NGLs for consumers in the Midwest and northeastern United States.

REFINED PRODUCTS
PIPELINES

PROPYLENE
FRACTIONATION

BUTANE
ISOMERIZATION

MARINE

TRANSPORTATION

The focal point of Enterprise's petrochemical services network is its Mont Belvieu, Texas complex, which features six propylene fractionation units with 87,000 BPD of capacity.

Propylene is used in the production of plastic consumer products, synthetic fibers, foams, fiber for carpets and upholstery, molded plastic parts for appliances, automobiles, housewares and medical products, and detergents and solvents. Growth in global demand for propylene is forecast to average around 5 percent per year from 2008 to 2013, according to the World Petrochemicals report on Propylene, issued by global petrochemical consulting firm, SRI Consulting.

Butane isomerization is the process of converting normal butane into mixed butane and subsequently fractionating it into isobutane, high purity isobutane and residual normal butane. Isobutane is primarily used for the production of propylene oxide, isooctane and alkylate for motor gasoline. Enterprise's butane isomerization facilities can produce up to 116,000 BPD of isobutane.

About 20 percent of the isobutane produced by the partnership is used as a feedstock for its state-of-the-art octane enhancement production facility at Mont Belvieu. The facility has capacity to produce 12,000 BPD of isooctane and isobutylene or 15,000 BPD of methyl tertiary butyl ether ("MTBE"). Any MTBE produced is sold into the export markets.

Enterprise's petrochemical pipelines are comprised of approximately 740 miles of pipelines that transport polymer-

grade propylene, chemical-grade propylene and high purity isobutane from our facilities to customer locations along the Texas and Louisiana Gulf Coast.

ACCOMPLISHMENTS

With the TEPPCO merger in 2009, Enterprise diversified its portfolio of assets with the addition of refined products pipelines, as well as related terminal and storage facilities.

The system includes approximately 5,700 miles of pipelines, which originate from the upper Texas Gulf Coast and extend into the Midwest, delivering gasoline, distillates and NGLs to consumers in the northeastern U.S. The acquired infrastructure also provides a foothold that will allow Enterprise to evaluate potential opportunities in the growing Marcellus Shale play. Complementing Enterprise's pipeline system is a network of terminals and storage facilities with 21 MMBbls of capacity for refined products and NGLs.

Through its marine transportation business, Enterprise has become a leading provider of services for moving refined products, crude oil, asphalt, condensate, heavy oil and other heated oil products along the nation's inland waterways. Utilizing its fleet of 69 tow boats and 136 barges, the partnership serves refiners and terminal customers, as well as offshore producers. The fleet was expanded during 2009 with the purchase of 19 boats and 28 barges from TransMontaigne Products Services. The acquired vessels primarily deliver fuel to cruise liners and cargo ships, as well as fuel oil for electric generation plants. The partnership believes its marine transportation assets will

extend the energy value chain by offering opportunities for further integration with other partnership assets.

During the second quarter of 2010, Enterprise began receiving deliveries of refined products at its new storage facility in Port Arthur, Texas. The \$330 million project involved construction of 20 tanks with a combined capacity of 5.4 million barrels and is designed to support the expansion of Motiva's nearby refinery. An 11-mile pipeline to connect the new storage facility in Port Arthur to Enterprise's products terminal in Beaumont, Texas was completed and began operations in December 2009.

2009 PERFORMANCE

The Petrochemical & Refined Products Services segment reported gross operating margin of \$365 million for 2009, compared to \$375 for the 2008 period. The partnership's octane enhancement business reported gross operating margin of \$12 million for 2009 compared to a loss of \$11 million for 2008, which reflects downtime and higher operating expenses during 2008. Propylene fractionation volumes increased 17 percent in 2009 to 68 MBPD compared to 58 MBPD during the 2008 period. The increase in volumes contributed \$90 million to 2009 gross operating margin as reported by the propylene fractionation business, which was higher than the \$87 million recorded in 2008. Although butane isomerization volumes



increased 13 percent to 97 MBPD in 2009 compared to 86 MBPD reported in 2008, gross operating margin from Enterprise's butane isomerization business decreased to \$76 million for 2009 from \$96 million for 2008 primarily due to lower plant by-product sales revenues resulting from lower commodity prices.

Gross operating margin from Enterprise's refined products pipelines and related activities was \$125 million for 2009 compared to \$133 million for 2008, while its marine transportation and other services business reported \$63 million of gross operating margin for 2009 compared to \$70 million for 2008.

HISTORY OF "BIG INCH, LITTLE BIG INCH"

The history of Enterprise's refined products pipeline network, acquired in the 2009 merger with TEPPCO Partners, L.P., dates back to the 1940s when it played a crucial role in assuring victory in World War II, and protecting the lives of soldiers and civilians in the process. During that time, the United States was responsible for approximately 60 percent of the world's crude oil production. Unfortunately, tankers carrying crude oil to East Coast refiners were frequently attacked and destroyed by German U-boats. Looking for a safer and more reliable solution, the federal government teamed up with numerous private companies for one of the most ambitious and successful projects of its kind—construction of the Big Inch and Little Big Inch pipelines.

Comprised of a 24-inch diameter crude oil pipeline that originated in Longview, Texas, and a 20-inch diameter refined products pipeline that began in Beaumont, Texas, these pipelines extended more than 1,300 miles to Linden, New Jersey, where the crude oil was refined and products, such as gasoline and diesel, were exported to Allied forces in Europe. These pipelines were among the first to utilize the newest "big inch" technology of the day that allowed steel pipe to be manufactured in diameters larger than 12 inches.

The mobilization of manpower, equipment and other resources was unprecedented by the time construction began in August of 1942. The initiative required more than 21,000 railcars of steel pipe, over 7,500 individual right-of-way agreements

and engineering plans for two pipelines that crossed 95 counties in 10 states, as well as several major rivers, including the Mississippi. Field operations consisted of eight crews of 350 to 400 workers each. Keeping the most experienced

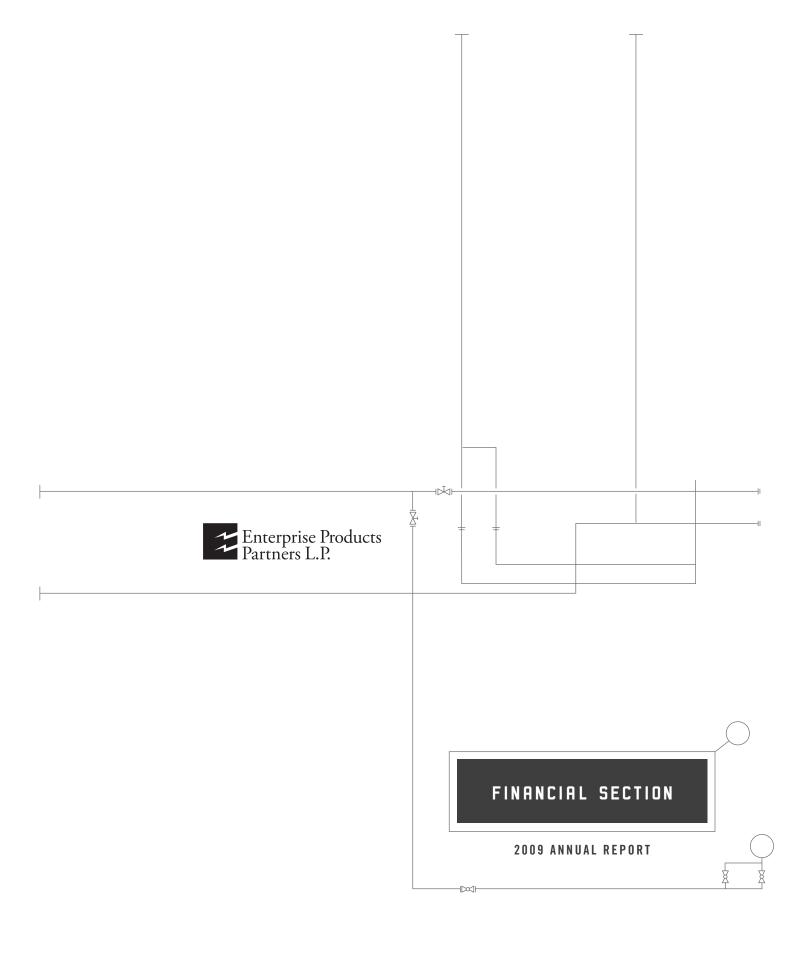
and knowledgeable pipeliners on the job proved to be especially challenging since many were drafted during construction.

Nevertheless, the final weld on the Big Inch pipeline was made July 19, 1943, just 350 days after the first shovel of earth was turned.

After the war, the pipelines went up for bid through the War Assets Administration. Texas Eastern Transmission Company, headed by its Chairman, George R. Brown

(inset photo, second from right), purchased the assets for \$143 million and converted them to natural gas service. In 1957, the Little Big Inch resumed deliveries of refined products. Over the years, the Little Big Inch, now called Enterprise TE Products Pipeline, has been expanded to serve new areas, and provide additional services, including transportation of propane and other NGLs to the Northeast. Recognizing the value of the system even today, Enterprise is leveraging the strategic location of the pipeline to pursue attractive growth opportunities to extend the partnership's integrated energy value chain into new areas.





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MARKET AND CASH DISTRIBUTION HISTORY FOR COMMON UNITS, RELATED UNITHOLDER MATTERS AND PURCHASES OF EQUITY SECURITIES

MARKET INFORMATION AND CASH DISTRIBUTIONS

Our common units are listed on the New York Stock Exchange ("NYSE") under the ticker symbol "EPD." As of February 1, 2010, there were approximately 1,772 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 with respect to such periods.

			CASH DISTRIBUTION HISTORY				
	PRICE RANGES		- PER	RECORD	PAYMENT		
	HIGH	LOW	ÜNİT	DATE	DATE		
2008							
1st Quarter	\$32.630	\$26.750	\$0.5075	Apr. 30, 2008	May 7, 2008		
2nd Quarter	\$32.640	\$29.040	\$0.5150	Jul. 31, 2008	Aug. 7, 2008		
3rd Quarter	\$30.070	\$22.580	\$0.5225	Oct. 31, 2008	Nov. 12, 2008		
4th Quarter	\$26.300	\$16.000	\$0.5300	Jan. 30, 2009	Feb. 9, 2009		
2009							
1st Quarter	\$24.200	\$17.710	\$0.5375	Apr. 30, 2009	May 8, 2009		
2nd Quarter	\$26.550	\$21.100	\$0.5450	Jul. 31, 2009	Aug. 7, 2009		
3rd Quarter	\$29.450	\$24.500	\$0.5525	Oct. 30, 2009	Nov. 5, 2009		
4th Quarter	\$32.240	\$27.250	\$0.5600	Jan. 29, 2010	Feb. 4, 2010		

The quarterly cash distributions shown in the table above correspond to cash flows for the quarters indicated. The actual cash distributions (i.e., the payments made to our common unitholders) occur within 45 days after the end of such quarter. We expect to fund our quarterly cash distributions to common unitholders 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 the Enterprise Products Partners L.P. ("Enterprise") Form 10-K. Although the payment of cash distributions is not guaranteed, we expect to continue to pay comparable cash distributions in the future.

RECENT SALES OF UNREGISTERED SECURITIES

On September 4, 2009, we agreed to issue 5,940,594 common units in a private placement to EPCO Holdings, Inc., a privately held affiliate controlled by Dan L. Duncan, for \$150.0 million. The private placement was exempt from the registration requirements of the Securities Act pursuant to Section 4(2) thereof, as a transaction by an issuer not involving any public offering. In accordance with the terms of the private placement, as approved by the Audit, Conflicts and Governance ("ACG") Committee of Enterprise Products GP, LLC's ("EPGP") Board of Directors on September 1, 2009, the per unit purchase price of \$25.25 was calculated based on a 5% discount to the five-day volume weighted-average price of our common units, as reported by the NYSE at the close of business on September 4, 2009. The common units were issued September 8, 2009.

Other than as described above, there were no sales of unregistered equity securities during 2009.

COMMON UNITS AUTHORIZED FOR ISSUANCE UNDER EQUITY COMPENSATION PLAN

See "Securities Authorized for Issuance Under Equity Compensation Plans" under Item 12 on page 129 of Enterprise's Form 10-K.

ISSUER PURCHASES OF EQUITY SECURITIES

In December 1998, we announced a common unit repurchase program whereby we, together with certain affiliates, intended to repurchase up to 2,000,000 of our common units for the purpose of granting options to management and key employees (amount adjusted for the 2-for-1 unit split in May 2002). We have not repurchased any of our common units since 2002 under this program. As of February 1, 2010, we and our affiliates could repurchase up to 618,400 additional common units under this repurchase program.

The following table summarizes our repurchase activity during 2009 in connection with other arrangements:

PERIOD	TOTAL NUMBER OF UNITS PURCHASED	AVERAGE PRICE PAID PER UNIT	TOTAL NUMBER OF UNITS PURCHASED AS PART OF PUBLICLY ANNOUNCED PLANS	MAXIMUM NUMBER OF UNITS THAT MAY YET BE PURCHASED UNDER THE PLANS
February 2009	1,357 (1)	\$22.64	_	_
May 2009	419 (2)	\$24.69	_	_
July 2009	610 (3)	\$28.10	_	_
August 2009	61,837 (4)	\$28.00	_	_
November 2009	9,477 (5)	\$28.36	_	_
December 2009	1,657 (6)	\$29.73	_	

- (1) Of the 11,000 restricted unit awards that vested in February 2009 and converted to common units, 1,357 of these units were sold back to the partnership by employees to cover related withholding tax requirements.
- (2) Of the 1,500 restricted unit awards that vested in May 2009 and converted to common units, 419 of these units were sold back to the partnership by employees to cover related withholding tax requirements.
- (3) Of the 2,300 restricted unit awards that vested in July 2009 and converted to common units, 610 of these units were sold back to the partnership by employees to cover related withholding tax requirements.
- (4) Of the 229,500 restricted unit awards that vested in August 2009 and converted to common units, 61,837 of these units were sold back to the partnership by employees to cover related withholding tax requirements.
- (5) Of the 31,000 restricted unit awards that vested in November 2009 and converted to common units, 9,477 of these units were sold back to the partnership by employees to cover related withholding tax requirements.
- (6) Of the 6,200 restricted unit awards that vested in December 2009 and converted to common units, 1,657 of these units were sold back to the partnership by employees to cover related withholding tax requirements.

EMPLOYEES

Like many publicly traded partnerships, we have no employees. All of our management, administrative and operating functions are performed by employees of Enterprise Products Company ("EPCO") pursuant to an administrative services agreement (the "ASA") or by other service providers. For additional information regarding the ASA, see "EPCO Administrative Services Agreement" in Note 15 of the Notes to Consolidated Financial Statements included in this annual report. As of December 31, 2009, there were approximately 4,800 EPCO personnel who spend all or a portion of their time engaged in our business. Approximately 3,300 of these individuals devote all of their time performing administrative, commercial and operating duties for us. The remaining approximate 1,500 personnel are part of EPCO's shared service organization and spend a portion of their time engaged in our business.

NYSE CORPORATE GOVERNANCE LISTING STANDARDS

On March 20, 2009, Michael A. Creel, 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 20, 2009.

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," "estimate," "forecast," "intend," "could," "should," "will," "believe," "may," "potential" and similar expressions and statements regarding our plans and objectives for future operations, are intended to identify forward-looking statements. Although we and our general partner believe that 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. If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, our actual results may vary materially from those anticipated, estimated, projected or expected. You should not put undue reliance on any forward-looking statements. The forward-looking statements in this annual report speak only as of the date hereof. Except as required by federal and state securities laws, we undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or any other reason.

GLOSSARY

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

MBbls = thousand barrels MMBbls = million barrels

MMBtus = million British thermal units

MMcf = million cubic feet

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of Enterprise Products GP, LLC and Unitholders of Enterprise Products Partners L.P. Houston, Texas

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

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

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

The consolidated financial statements give retroactive effect to the acquisition of TEPPCO Partners, L.P. ("TEPPCO") and Texas Eastern Products Pipeline Company, LLC ("TEPPCO GP") by the Company on October 26, 2009, which has been accounted for at historical cost as a reorganization of entities under common control as described in Note 1 to the consolidated financial statements. Also, as discussed in Note 1 to the consolidated financial statements, the disclosures in the accompanying consolidated financial statements have been retrospectively adjusted for a change in the composition of reportable segments as a result of the acquisition of TEPPCO and TEPPCO GP by the Company.

DELOITTE & TOUCHE LLP

Daite + Touche LLP

Houston, Texas March 1, 2010

CONSOLIDATED BALANCE SHEETS (Dollars in millions)

	DECEMBER 31,	
ASSETS	2009	2008*
Current assets:		
Cash and cash equivalents	\$ 54.7	\$ 61.7
Restricted cash	63.6	203.8
Accounts and notes receivable – trade, net of allowance for doubtful accounts of \$16.8 at December 31, 2009 and \$17.7 at December 31, 2008	3,099.0	2,028.5
Accounts receivable – related parties	38.4	35.3
Inventories	711.9	405.0
Derivative assets	113.8	218.6
	165.5	
Prepaid and other current assets Total current assets		149.8
	4,246.9	3,102.7
Property, plant and equipment, net	17,689.2	16,732.8
Investments in unconsolidated affiliates	890.6	911.9
Intangible assets, net of accumulated amortization of \$795.0 at December 31, 2009 and \$675.1 at December 31, 2008	1,064.8	1,182.9
Goodwill	2,018.3	2,019.6
Other assets	241.8	261.7
Total assets	\$ 26,151.6	\$ 24,211.6
LIABILITIES AND EQUITY Current liabilities:		
Accounts payable – trade	\$ 410.6	\$ 388.9
. ,	•	•
Accounts payable – related parties	69.8	17.4
Accrued product payables	3,393.0	1,845.7
Accrued expenses	108.5	65.7
Accrued interest	228.0	188.3
Derivative liabilities	93.0	302.9
Other current liabilities	233.1	292.3
Total current liabilities	4,536.0	3,101.2
Long-term debt: (see Note 12)		
Senior debt obligations – principal	9,764.3	10,030.1
Junior subordinated notes – principal	1,532.7	1,532.7
Other	49.4	75.1
Total long-term debt	11,346.4	11,637.9
Deferred tax liabilities	71.7	66.1
Other long-term liabilities	155.2	110.5
Commitments and contingencies		
Equity: (see Note 13)		
Enterprise Products Partners L.P. partners' equity:		
Limited Partners:		
Common units (603,202,828 units outstanding at December 31, 2009 and 439,354,731 units outstanding at December 31, 2008)	9,173.5	6,036.9
Restricted common units (2,720,882 units outstanding at December 31, 2009 and 2,080,600 units outstanding at December 31, 2008)	37.7	26.2
Class B units (4,520,431 units outstanding at December 31, 2009)	118.5	_
General partner	190.8	123.6
Accumulated other comprehensive loss	(8.4)	(97.2)
Total Enterprise Products Partners L.P. partners' equity	9,512.1	6,089.5
Noncontrolling interest	530.2	3,206.4
Total equity	10,042.3	9,295.9
Total liabilities and equity	\$ 26,151.6	\$ 24,211.6

^{*}See Note 1 for information regarding these recasted amounts and basis of financial statement presentation.

STATEMENTS OF CONSOLIDATED OPERATIONS (Dollars in millions, except per unit amounts)

	FOR YEAR ENDED DECEMBER 31,				31,	
		2009		2008*		2007*
Revenues:						
Third parties	\$	24,911.9	\$	34,454.2	\$	26,128.6
Related parties		599.0		1,015.4		585.2
Total revenues (see Note 14)		25,510.9		35,469.6		26,713.8
Costs and expenses:						
Operating costs and expenses:						
Third parties		22,547.6		32,861.9		24,938.2
Related parties		1,018.2		757.0		463.9
Total operating costs and expenses	•	23,565.8		33,618.9		25,402.1
General and administrative costs:	-					
Third parties		77.3		43.4		44.6
Related parties		95.0		93.8		82.6
Total general and administrative costs		172.3		137.2		127.2
Total costs and expenses		23,738.1		33,756.1		25,529.3
Equity in income of unconsolidated affiliates		51.2		34.9		10.5
Operating income		1,824.0		1,748.4		1,195.0
Other income (expense):						
Interest expense		(641.8)		(540.7)		(413.0)
Interest income		2.3		7.4		11.1
Other, net		(4.1)		4.8		60.6
Total other expense, net	-	(643.6)		(528.5)		(341.3)
Income before provision for income taxes	•	1,180.4		1,219.9		853.7
Provision for income taxes		(25.3)		(31.0)		(15.7)
Net income	•	1,155.1		1,188.9		838.0
Net income attributable to noncontrolling interest (see Note 13)		(124.2)		(234.9)		(304.4)
Net income attributable to Enterprise Products Partners L.P.	\$	1,030.9	\$	954.0	\$	533.6
Net income allocated to: (see Note 13)						
Limited partners	\$	852.2	\$	811.5	\$	417.7
General partner	\$	178.7	\$	142.5	<u>Ψ</u>	115.9
deficial partitor	_Ψ_	170.7	Ψ	172.3	Ψ	113.3
Earnings per unit: (see Note 17)			_		_	
Basic and diluted earnings per unit	\$_	1.73	\$	1.84	\$	0.95

^{*}See Note 1 for information regarding these recasted amounts and basis of financial statement presentation.

STATEMENTS OF CONSOLIDATED COMPREHENSIVE INCOME (Dollars in millions)

	FOR YEAR ENDED DECEMBER 31,			
	2009	2008*	2007*	
Net income	\$ 1,155.1	\$ 1,188.9	\$ 838.0	
Other comprehensive income (loss):				
Cash flow hedges:				
Commodity derivative instrument losses during period	(179.6)	(170.2)	(46.9)	
Reclassification adjustment for losses included in net income				
related to commodity derivative instruments	294.2	96.3	9.5	
Interest rate derivative instrument gains (losses) during period	18.6	(52.0)	(8.9)	
Reclassification adjustment for (gains) losses included in net income				
related to interest rate derivative instruments	10.8	(1.1)	(5.8)	
Foreign currency derivative gains (losses)	(10.2)	9.3	1.3	
Total cash flow hedges	133.8	(117.7)	(50.8)	
Foreign currency translation adjustment	2.1	(2.5)	2.0	
Change in funded status of pension and postretirement plans, net of tax	_	(1.3)	_	
Total other comprehensive income (loss)	135.9	(121.5)	(48.8)	
Comprehensive income	1,291.0	1,067.4	789.2	
Comprehensive income attributable to noncontrolling interest	(130.2)	(229.7)	(258.8)	
Comprehensive income attributable to Enterprise Products Partners L.P.	\$ 1,160.8	\$ 837.7	\$ 530.4	

 $^{^{*}}$ See Note 1 for information regarding these recasted amounts and basis of financial statement presentation.

STATEMENTS OF CONSOLIDATED CASH FLOWS (Dollars in millions)

	FOR YEAR ENDED DECEMBER 31,		
	2009	2008*	2007*
Operating activities:			
Net income	\$ 1,155.1	\$ 1,188.9	\$ 838.0
Adjustments to reconcile net income to net cash flows provided by operating activities:		. ,	
Depreciation, amortization and accretion	833.4	737.8	658.4
Non-cash impairment charges	33.5	_	_
Equity in income of unconsolidated affiliates	(51.2)	(34.9)	(10.5)
Distributions received from unconsolidated affiliates	86.6	80.8	87.0
Operating lease expenses paid by EPCO	0.7	2.0	2.1
Gain from asset sales and related transactions	_	(4.0)	(67.4)
Loss on forfeiture of investment in Texas Offshore Port System	68.4	_	_
Loss on early extinguishment of debt	_	1.6	1.6
Deferred income tax expense	4.5	6.2	7.6
Changes in fair market value of derivative instruments	0.4	(0.1)	1.3
Effect of pension settlement recognition	(0.1)	(0.1)	0.6
Net effect of changes in operating accounts (see Note 20)	245.9	(411.1)	434.9
Net cash flows provided by operating activities	2,377.2	1,567.1	1,953.6
Investing activities:			
Capital expenditures	(1,584.3)	(2,539.6)	(2,764.0)
Contributions in aid of construction costs	17.8	27.2	57.6
Decrease (increase) in restricted cash	140.2	(132.8)	(47.3)
Cash used for business combinations (see Note 10)	(107.3)	(553.5)	(35.9)
Acquisition of intangible assets	(1.4)	(5.8)	(14.5)
Investments in unconsolidated affiliates	(18.8)	(64.7)	(236.8)
Proceeds from asset sales and related transactions	3.6	22.3	169.1
Other investing activities	3.3		
Cash used in investing activities	(1,546.9)	(3,246.9)	(2,871.8)
Financing activities:			
Borrowings under debt agreements	7,376.6	13,188.0	7,629.8
Repayments of debt	(7,653.5)	(10,434.3)	(5,799.9)
Debt issuance costs	(14.9)	(27.6)	(20.6)
Cash distributions paid to partners	(1,254.8)	(1,037.4)	(957.7)
Cash distributions paid to noncontrolling interest	(340.0)	(383.9)	(326.8)
Cash contributions from noncontrolling interest	138.7	311.5	304.7
Net cash proceeds from issuance of common units	912.7	142.8	69.2
Repurchase of restricted units and options	_	_	(1.5)
Acquisition of treasury units	(2.1)	(1.9)	_
Monetization of interest rate derivative instruments (see Note 6)	0.2	(66.5)	49.1
Cash provided by (used in) financing activities	(837.1)	1,690.7	946.3
Effect of exchange rate changes on cash	(0.2)	(0.5)	0.4
Net change in cash and cash equivalents	(6.8)	10.9	28.1
Cash and cash equivalents, January 1	61.7	51.3	22.8
Cash and cash equivalents, December 31	\$ 54.7	\$ 61.7	\$ 51.3

^{*}See Note 1 for information regarding these recasted amounts and basis of financial statement presentation.

STATEMENTS OF CONSOLIDATED EQUITY
(See Note 13 for Unit History, Detail of Changes in Limited Partners' Equity and Accumulated Other Comprehensive Income (Loss)) (Dollars in millions)

	ENTERPRISE PRODUCTS PARTNERS L.P.					
	LIMITED Partners	GENERAL PARTNER	ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)	NONCONTROLLING INTEREST	TOTAL	
Balance, December 31, 2006*	\$ 6,329.8	\$ 129.3	\$ 21.1	\$ 2,644.7	\$ 9,124.9	
Net income	417.7	115.9	_	304.4	838.0	
Operating lease expenses paid by EPCO	2.1	_	_	_	2.1	
Cash distributions paid to partners	(833.8)	(124.4)	_	_	(958.2)	
Unit option reimbursements to EPCO	(3.0)	_	_	_	(3.0)	
Cash distributions paid to noncontrolling interest	_	_	_	(326.8)	(326.8)	
Net cash proceeds from issuance of common units	60.4	1.2	_	_	61.6	
Cash proceeds from exercise of unit options	7.5	0.1	_	_	7.6	
Cash contributions from noncontrolling interest	_	_	_	304.7	304.7	
Repurchase of restricted units and options	(1.5)	_	_	_	(1.5)	
Amortization of equity awards	13.7	0.2	_	0.8	14.7	
Change in funded status of pension and						
postretirement plans, net of tax	_	_	1.2	_	1.2	
Foreign currency translation adjustment	_	_	2.0	_	2.0	
Cash flow hedges			(5.2)	(45.6)	(50.8)	
Balance, December 31, 2007*	5,992.9	122.3	19.1	2,882.2	9,016.5	
Net income	811.5	142.5	_	234.9	1,188.9	
Operating lease expenses paid by EPCO	2.0	_	_	_	2.0	
Cash distributions paid to partners	(892.7)	(144.1)	_	_	(1,036.8)	
Unit option reimbursements to EPCO	(0.6)	_	_	_	(0.6)	
Cash distributions paid to noncontrolling interest	_	_	_	(383.9)	(383.9)	
Acquisition of treasury units	(1.9)	_	_	_	(1.9)	
Net cash proceeds from issuance of common units	139.3	2.8	_	_	142.1	
Cash proceeds from exercise of unit options	0.7	_	_	_	0.7	
Cash contributions from noncontrolling interest	_	_	_	311.5	311.5	
Issuance of units by TEPPCO in connection with Cenac acquisition (see Note 10)	_	_	_	186.6	186.6	
Amortization of equity awards	11.9	0.1	_	2.1	14.1	
Acquisition of additional interest in subsidiaries	_	_	_	(22.3)	(22.3)	
Change in funded status of pension and postretirement plans, net of tax	_	_	(1.3)	_	(1.3)	
Foreign currency translation adjustment	_	_	(2.5)	_	(2.5)	
Cash flow hedges	_	_	(112.5)	(5.2)	(117.7)	
Other				0.5	0.5	
Balance, December 31, 2008*	6,063.1	123.6	(97.2)	3,206.4	9,295.9	
Net income	852.2	178.7	_	124.2	1,155.1	
Operating lease expenses paid by EPCO	0.7	_	_	_	0.7	
Cash distributions paid to partners	(1,069.3)	(183.1)	_	_	(1,252.4)	
Unit option reimbursements to EPCO	(2.4)	_	_	_	(2.4)	
Cash distributions paid to noncontrolling interest	_	_	_	(340.0)	(340.0)	
Acquisition of treasury units	(2.1)	_	_	_	(2.1)	
Net cash proceeds from issuance of common units	892.8	18.2	_	_	911.0	
Cash proceeds from exercise of unit options	1.7	_	_	_	1.7	
Common and Class B units issued in connection with TEPPCO Merger	2,574.1	53.1	(41.1)	(2,585.8)	0.3	
Deconsolidation of Texas Offshore Port System	_	_	_	(33.4)	(33.4)	
Acquisition of interest in subsidiary	_	_	_	10.3	10.3	
Cash contributions from noncontrolling interest	_	_	_	138.7	138.7	
Amortization of equity awards	18.9	0.3	_	4.1	23.3	
Foreign currency translation adjustment	_	_	2.1	_	2.1	
Cash flow hedges	_	_	127.8	6.0	133.8	
Other				(0.3)	(0.3)	
Balance, December 31, 2009	\$ 9,329.7	\$ 190.8	\$ (8.4)	\$ 530.2	\$10,042.3	

^{*}See Note 1 for information regarding these recasted amounts and basis of financial statement presentation.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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

NOTE 1. PARTNERSHIP ORGANIZATION AND BASIS OF PRESENTATION

Enterprise Products Partners L.P. is a publicly traded Delaware limited partnership, the common units of which are listed on the NYSE under the ticker symbol "EPD." We were formed in April 1998 to own and operate certain natural gas liquids ("NGLs") related businesses of EPCO. We conduct substantially all of our business through our wholly owned subsidiary, Enterprise Products Operating LLC ("EPO"). We are owned 98% by our limited partners and 2% by our general partner, EPGP. Enterprise GP Holdings L.P. ("Enterprise GP Holdings") owns 100% of EPGP. The general partner of Enterprise GP Holdings is EPE Holdings, LLC ("EPE Holdings"), a wholly owned subsidiary of Dan Duncan LLC, all of the membership interests of which are owned by Dan L. Duncan. We, EPGP, Enterprise GP Holdings, EPE Holdings and Dan Duncan LLC are affiliates and under common control of Dan L. Duncan, the Group Co-Chairman and controlling shareholder of EPCO.

On October 26, 2009, the related mergers of our wholly owned subsidiaries with TEPPCO and TEPPCO GP were completed. See "TEPPCO Merger and Basis of Presentation" within this Note 1 for additional information regarding the TEPPCO Merger.

On February 5, 2007, Duncan Energy Partners L.P. ("Duncan Energy Partners"), a consolidated subsidiary of ours, completed an initial public offering of its common units. Through its initial public offering and a subsequent drop down transaction on December 8, 2008, Duncan Energy Partners owns equity interests in certain of our midstream energy businesses. DEP Holdings, LLC ("DEP GP"), the general partner of Duncan Energy Partners, is wholly owned by EPO.

For financial reporting purposes, we consolidate the financial statements of Duncan Energy Partners with those of our own and reflect its operations in our business segments. We control Duncan Energy Partners through our ownership of its general partner. Also, due to common control of the entities by Dan L. Duncan, the initial consolidated balance sheet of Duncan Energy Partners reflects our historical carrying basis in each of the subsidiaries contributed to Duncan Energy Partners. Public ownership of Duncan Energy Partners' net assets and earnings are presented as a component of noncontrolling interest in our consolidated financial statements. The borrowings of Duncan Energy Partners are presented as part of our consolidated debt. However, neither Enterprise Products Partners L.P. nor EPO have any obligation for the payment of interest or repayment of borrowings incurred by Duncan Energy Partners.

TEPPCO Merger and Basis of Presentation

On October 26, 2009, the related mergers of our wholly owned subsidiaries with TEPPCO and TEPPCO GP were completed. Under terms of the merger agreements, TEPPCO and TEPPCO GP became wholly owned subsidiaries of ours, and each of TEPPCO's unitholders, except for a privately held affiliate of EPCO, were entitled to receive 1.24 of our common units for each TEPPCO unit. In total, we issued an aggregate of 126,932,318 common units and 4,520,431 Class B units (described below) as consideration in the TEPPCO Merger for both TEPPCO units and the TEPPCO GP membership interests. TEPPCO's units, which had been trading on the NYSE under the ticker symbol "TPP," have been delisted and are no longer publicly traded. On October 27, 2009, our TEPPCO and TEPPCO GP equity interests were contributed to EPO, and TEPPCO and TEPPCO GP became wholly owned subsidiaries of EPO.

A privately held affiliate of EPCO exchanged a portion of its TEPPCO units, based on the 1.24 exchange rate, for 4,520,431 of our Class B units in lieu of common units. The Class B units are not entitled to regular quarterly cash distributions for the first sixteen quarters following the closing date of the merger. The Class B units automatically convert into the same number of common units on the date immediately following the payment date for the sixteenth quarterly distribution following the closing date of the merger. The Class B units are entitled to vote together with the common units as a single class on partnership matters and, except for the payment of distributions, have the same rights and privileges as our common units.

Under the terms of the TEPPCO Merger agreements, Enterprise GP Holdings received 1,331,681 of our common units and an increase in the capital account of EPGP to maintain its 2% general partner interest in us as consideration for 100% of the membership interests of TEPPCO GP.

Since Enterprise Products Partners, TEPPCO and TEPPCO GP are under common control of EPCO and its affiliates, the TEPPCO Merger was accounted for at historical costs as a reorganization of entities under common control in a manner similar to a pooling of interests. The inclusion of TEPPCO and TEPPCO GP in our consolidated financial statements was effective January 1, 2005 since an affiliate of EPCO under common control with Enterprise Products Partners originally acquired ownership interests in TEPPCO GP in February 2005.

Our consolidated financial statements prior to the TEPPCO Merger reflect the combined financial information of Enterprise Products Partners, TEPPCO and TEPPCO GP on a 100% basis. Third-party and related party ownership interests in TEPPCO and TEPPCO GP are reflected as "Former owners of TEPPCO," a component of noncontrolling interest.

Our financial statements have been prepared in accordance with U.S. generally accepted accounting principles ("GAAP"). The financial statements of TEPPCO and TEPPCO GP were prepared from the separate accounting records maintained by TEPPCO and TEPPCO GP. All intercompany balances and transactions have been eliminated in consolidation.

We revised our business segments and related disclosures to reflect the TEPPCO Merger. Our reorganized business segments reflect the manner in which these businesses are managed and reviewed by the chief executive officer of our general partner. Under our new business segment structure, we have five reportable business segments: (i) NGL Pipelines & Services; (ii) Onshore Natural Gas Pipelines & Services; (iii) Onshore Crude Oil Pipelines & Services; (iv) Offshore Pipelines & Services; and (v) Petrochemical & Refined Products Services.

There was no change in net income attributable to Enterprise Products Partners L.P. for periods prior to the merger since net income attributable to TEPPCO and TEPPCO GP was allocated to noncontrolling interests. Additionally, there was no change in our reported earnings per unit for such periods. See Note 14 for a reconciliation of our consolidated revenues and total segment gross operating margin, which is a non-generally accepted accounting principle ("non-GAAP") financial measure of segment performance, to our pre-merger amounts.

NOTE 2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Allowance for Doubtful Accounts

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

The following table presents the activity of our allowance for doubtful accounts for the periods indicated:

FOR YEAR ENDED DECEMBER 31,					
2009	2008	2007			
\$ 17.7	\$ 21.8	\$ 23.5			
0.1	3.5	2.6			
(1.0)	(7.6)	(4.3)			
\$ 16.8	\$ 17.7	\$ 21.8			
	2009 \$ 17.7 0.1 (1.0)	2009 2008 \$ 17.7 \$ 21.8 0.1 3.5 (1.0) (7.6)			

See "Credit Risk Due to Industry Concentrations" in Note 19 for additional information.

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.

Consolidation Policy

Our consolidated financial statements include our accounts and those of our majority-owned subsidiaries in which we have a controlling interest, after the elimination of all intercompany accounts and transactions. We 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. 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. Third-party or affiliate ownership interests in our controlled subsidiaries are presented as noncontrolling interests. See Note 13 for information regarding noncontrolling interest.

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

If our ownership interest in an entity does not provide us with either control or significant influence, we 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 its legal counsel assess such contingent liabilities, and such assessment inherently involves an exercise in judgment. In assessing loss contingencies related to legal proceedings that are pending against us or unasserted claims that may result in proceedings, our management and legal counsel evaluate the perceived merits of any legal proceedings or unasserted claims as well as the perceived merits of the amount of relief sought or expected to be sought therein.

If the assessment of a contingency indicates that it is probable that a material loss has been incurred and the amount of liability can be estimated, then the estimated liability would be accrued in our financial statements. If the assessment indicates that a potentially 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 and material), is disclosed.

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

Current Assets and Current Liabilities

We present, as individual captions in our Consolidated Balance Sheets, all components of current assets and current liabilities that exceed 5% of total current assets and liabilities, respectively.

Deferred Revenues

Amounts billed in advance of the period in which the service is rendered or product delivered are recorded as deferred revenue. At December 31, 2009 and 2008, deferred revenues totaled \$106.8 million and \$118.5 million, respectively, and were recorded as a component of other current and long-term liabilities, as appropriate, on our Consolidated Balance Sheets. See Note 4 for information regarding our revenue recognition policies.

Derivative Instruments

We use derivative instruments such as swaps, forwards and other contracts to manage price risks associated with inventories, firm commitments, interest rates, foreign currency and certain anticipated transactions. To qualify for hedge accounting, the item to be hedged must expose us to risk and the related derivative instrument must reduce that exposure and meet specific documentation requirements. We formally designate a derivative instrument as a hedge and document and assess the effectiveness of the hedge at inception and thereafter on a quarterly basis. We also apply the normal purchases/normal sales exception for certain of our derivative instruments, which precludes the recognition of changes in mark-to-market value for these items on the balance sheet or income statement. Revenues and costs for these transactions are recognized when volumes are physically delivered or received. See Note 6 for additional information regarding our derivative instruments and related hedging activities.

Earnings Per Unit

Earnings per unit ("EPU") is based on the amount of income allocated to limited partners and the weighted-average number of units outstanding during the period. See Note 17 for additional 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 best estimate of the ultimate cost to remediate a site and are adjusted as further information and circumstances develop. Those estimates may change substantially depending on information about the nature and extent of contamination, appropriate remediation technologies and regulatory approvals. Expenditures to mitigate or prevent future environmental contamination are capitalized. Ongoing environmental compliance costs are charged to expense as incurred. In accruing for environmental remediation liabilities, costs of future expenditures for environmental remediation are not discounted to their present value, unless the amount and timing of the expenditures are fixed or reliably determinable. At December 31, 2009, none of our estimated environmental remediation liabilities were discounted to present value since the ultimate amount and timing of cash payments for such liabilities were not readily determinable.

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

	FOR YEAR ENDED DECEMBER 31,					
	2009	2008	2007			
Balance at beginning of period	\$ 22.3	\$ 30.5	\$ 26.0			
Charges to expense	1.9	3.1	4.2			
Acquisition-related additions and other	_	2.9	6.7			
Payments	(5.1)	(8.3)	(6.1)			
Adjustments	(2.4)	(5.9)	(0.3)			
Balance at end of period	\$ 16.7	\$ 22.3	\$ 30.5			

At December 31, 2009 and 2008, \$6.4 million and \$5.3 million, respectively, of our environmental reserves were classified as current liabilities.

Equity Awards

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

Estimates

Preparing our financial statements in conformity with GAAP requires management to make estimates and assumptions that affect amounts presented in the financial statements (i.e., assets, liabilities, revenue and expenses) and disclosures about contingent assets and liabilities. Our actual results could differ from these estimates. On an ongoing basis, management reviews its estimates based on currently available information. Changes in facts and circumstances may result in revised estimates.

Exchange Contracts

Exchanges are contractual agreements for the movements of NGLs and certain petrochemical products between parties to satisfy timing and logistical needs of the parties. Net exchange volumes borrowed from us under such agreements are valued at market-based prices and included in accounts receivable. Net exchange volumes loaned to us under such agreements are valued at market-based prices and accrued as a liability in accrued product payables.

Receivables and payables arising from exchange transactions are settled with movements of products rather than with cash. When payment or receipt of monetary consideration is required for product differentials and service costs, such items are recognized in our consolidated financial statements on a net basis.

Fair Value Information

Cash and cash equivalents and restricted cash, accounts receivable, accounts payable and accrued expenses, and other current liabilities are carried at amounts which reasonably approximate their fair values due to their short-term nature. The estimated fair values of our fixed-rate debt are based on quoted market prices for such debt or debt of similar terms and maturities. The carrying amounts of our variable-rate debt obligations reasonably approximate their fair values due to their variable interest rates. See Note 6 for fair value information associated with our derivative instruments.

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

	DECEMBE	R 31, 2009	DECEMBER 31, 2008	
FINANCIAL INSTRUMENTS	CARRYING VALUE	FAIR VALUE	CARRYING VALUE	FAIR VALUE
Financial assets:				
Cash and cash equivalents and restricted cash	\$ 118.3	\$ 118.3	\$ 265.5	\$ 265.5
Accounts receivable	3,137.4	3,137.4	2,063.8	2,063.8
Financial liabilities:				
Accounts payable and accrued expenses	4,209.9	4,209.9	2,506.0	2,506.0
Other current liabilities	233.1	233.1	292.3	292.3
Fixed-rate debt (principal amount)	10,586.7	11,056.2	9,704.3	8,192.2
Variable-rate debt	710.3	710.3	1,858.5	1,858.5

Foreign Currency Translation

We own an NGL marketing business located in Canada. The financial statements of this foreign subsidiary are translated into U.S. dollars from the Canadian dollar, which is the subsidiary's functional currency, using the current rate method. Its assets and liabilities are translated at the rate of exchange in effect at the balance sheet date, while revenue and expense items are translated at average rates of exchange during the reporting period. Exchange gains and losses arising from foreign currency translation adjustments are reflected as separate components of accumulated other comprehensive loss ("AOCI") in the accompanying Consolidated Balance Sheets. Our net cash flows from this Canadian subsidiary may be adversely affected by changes in foreign currency exchange rates. See Note 6 for information regarding our foreign currency derivative 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. See Note 6 for information regarding impairment charges related to goodwill during 2009.

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 when events or changes in circumstances indicate that the carrying amount of such assets may not be recoverable.

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

Impairment Testing for Unconsolidated Affiliates

We evaluate our equity method investments for impairment when events or changes in circumstances indicate that there is a loss in value of the investment attributable to an other than temporary decline. Examples of such events or changes in circumstances include continuing operating losses of the entity and/or long-term negative changes in the entity's industry. In the event we determine that the loss in value of an investment is other than a temporary decline, we record a charge to equity earnings to adjust the carrying value of the investment to its estimated fair value. See Note 9 for information regarding impairment charges related to our unconsolidated affiliates during 2007.

Income Taxes

Provision for income taxes is primarily applicable to our state tax obligations under the Revised Texas Franchise Tax and certain federal and state tax obligations of Seminole Pipeline Company ("Seminole") and Dixie Pipeline Company ("Dixie"), both of which are consolidated subsidiaries of ours. 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.

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. Since we do not have access to information regarding each partner's tax basis, we cannot readily determine the total difference in the basis of our net assets for financial and tax reporting purposes.

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. See Note 16 for additional information regarding our income taxes.

Inventories

Inventories primarily consist of natural gas, NGLs, crude oil, refined products, lubrication oils and certain petrochemical products that are valued at the lower of average cost or market ("LCM"). We capitalize, as a cost of inventory, shipping and handling charges associated with such purchase volumes, terminal storage fees, vessel inspection costs, demurrage charges and other related costs. As volumes are sold and delivered out of inventory, the cost of these volumes (including freight-in charges that have been capitalized as part of inventory cost) are charged to operating costs and expenses. Shipping and handling fees associated with products we sell and deliver to customers are charged to operating costs and expenses as incurred. See Note 7 for additional information regarding our inventories.

Natural Gas Imbalances

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

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

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

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

	DECEMBER 31,		
	2009 2008		
Natural gas imbalance receivables (1)	\$ 24.1	\$ 63.4	
Natural gas imbalance payables (2)	19.0	50.8	

- Reflected as a component of "Accounts and notes receivable trade" on our Consolidated Balance Sheets.
- Reflected as a component of "Accrued product payables" on our Consolidated Balance Sheets.

Property, Plant and Equipment

Property, plant and equipment is recorded at cost. Expenditures for additions, improvements and other enhancements to property, plant and equipment are capitalized and 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 is 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, 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: (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 8 for additional information regarding our property, plant and equipment.

Certain of our plant operations entail 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 our planned major maintenance activities; however, the cost of annual planned major maintenance projects are deferred and recognized ratably over the remaining portion of the calendar year in which such projects occur.

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.

Restricted Cash

Restricted cash represents amounts held in connection with our commodity derivative instruments portfolio and related physical natural gas and NGL purchases. Additional cash may be restricted to maintain this portfolio as commodity prices fluctuate or deposit requirements change. At December 31, 2009 and 2008, our restricted cash amounts were \$63.6 million and \$203.8 million, respectively. See Note 6 for information regarding derivative instruments and hedging activities.

Revenue Recognition

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

NOTE 3. RECENT ACCOUNTING DEVELOPMENTS

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

<u>Fair Value Measurements</u>. In January 2010, the Financial Accounting Standards Board ("FASB") issued new guidance to improve disclosures about fair value measurements. This new guidance requires the following:

- Effective with the first quarter of 2010, additional disclosures will be required regarding the reporting of transfers of fair value information between the three levels of the fair value hierarchy (i.e., Levels 1, 2 and 3).
- Effective with the first quarter of 2011, companies will need to present purchases, sales, issuances and settlements whose fair values are based on unobservable inputs on a gross basis.

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

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

NOTE 4. REVENUE RECOGNITION

The following information provides a general description of our underlying revenue recognition policies by business segment:

NGL Pipelines & Services

Our NGL Pipelines & Services include our: (i) natural gas processing business and related NGL marketing activities; (ii) NGL pipelines aggregating approximately 16,300 miles; (iii) NGL and related product storage and terminal facilities; and (iv) NGL fractionation facilities. This segment also includes our import and export terminal operations.

In our natural gas processing business, we enter into percent-of-liquids contracts, percent-of-proceeds contracts, fee-based contracts, hybrid-contracts (i.e., a combination of percent-of-liquids and fee-based contract terms), keepwhole contracts and margin-band contracts. Under keepwhole and margin-band contracts, we take ownership of mixed NGLs extracted from the producer's natural gas stream and recognize revenue when the extracted NGLs are delivered and sold to customers under NGL marketing sales contracts. In the same way, revenue is recognized under our percent-of-liquids contracts except that the volume of NGLs we extract and sell is less than the total amount of NGLs extracted from the producers' natural gas. Under a percent-of-liquids contract, the producer retains title to the remaining percentage of mixed NGLs we extract. Under a percent-of-proceeds contract, we share in the proceeds generated from the sale of the mixed NGLs we extract on the producer's behalf. If a cash fee for natural gas processing services is stipulated by the contract, we record revenue when the natural gas has been processed and delivered to the producer.

Our NGL marketing activities generate revenues from the sale and delivery of NGLs obtained through our processing activities and spot and contract purchases from third parties. Revenues from these sales contracts are recognized when the NGLs are delivered to customers. In general, sales prices referenced in these contracts are market-based and may include pricing differentials for such factors as delivery location.

Under our NGL pipeline transportation contracts and tariffs, revenue is recognized when volumes have been delivered to customers. Revenue from these contracts and tariffs is generally based upon a fixed fee per gallon of liquids transported multiplied by the volume delivered. Transportation fees charged under these arrangements are either contractual or regulated by governmental agencies such as the Federal Energy Regulatory Commission ("FERC").

We collect storage revenues under our NGL and related product storage contracts based on the number of days a customer has volumes in storage multiplied by a storage rate (as defined in each contract). Under these contracts, revenue is recognized ratably over the length of the storage period. With respect to capacity reservation agreements, we collect a fee for reserving storage capacity for certain 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 charge other customers throughput fees based on volumes delivered into and subsequently withdrawn from storage, which are recognized as the service is provided.

We enter into fee-based arrangements and percent-of-liquids contracts for the NGL fractionation services we provide to customers. Under such fee-based arrangements, revenue is recognized in the period services are provided. Such fee-based arrangements typically include a base-processing fee (usually stated in cents per gallon) that is contractually subject to adjustment for changes in certain fractionation expenses (e.g., natural gas fuel costs). Certain of our NGL fractionation facilities generate revenues using percent-of-liquids contracts. Such contracts allow us to retain a contractually determined percentage of the customer's fractionated NGL products as payment for services rendered. Revenue is recognized from such arrangements when we sell and deliver the retained NGLs to customers.

Revenues from product terminaling activities are recorded in the period such services are provided. Customers are typically billed a fee per unit of volume loaded or unloaded. With respect to our export terminal operations, revenues may also include demand payments charged to customers who reserve the use of our export facilities and later fail to use them. Demand fee revenues are recognized when the customer fails to utilize the specified export facility as required by contract.

Onshore Natural Gas Pipelines & Services

Our Onshore Natural Gas Pipelines & Services include approximately 19,200 miles of onshore natural gas pipeline systems that provide for the gathering and transportation of natural gas in Alabama, Colorado, Louisiana, Mississippi, New Mexico, Texas and Wyoming. We own two salt dome natural gas storage facilities located in Mississippi and lease natural gas storage facilities located in Texas and Louisiana. This segment also includes our natural gas marketing activities.

Our onshore natural gas pipelines typically generate revenues from transportation agreements where shippers are billed a fee per unit of volume transported (typically per MMBtu) multiplied by the volume gathered or delivered. The transportation fees charged under these arrangements are either contractual or regulated by governmental agencies, including the FERC. Certain of our onshore natural gas pipelines offer firm capacity reservation services whereby the shipper pays a contractually stated fee based on the level of throughput capacity reserved in our pipelines whether or not the shipper actually utilizes such capacity. Revenues under firm capacity reservation agreements are recognized in the period the services are provided.

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

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

Onshore Crude Oil Pipelines & Services

Our Onshore Crude Oil Pipelines & Services include approximately 4,400 miles of onshore crude oil pipelines and 10.5 MMBbls of above-ground storage tank capacity. This segment includes our crude oil marketing activities.

Revenue from crude oil transportation is generally based upon a fixed fee per barrel transported multiplied by the volume delivered. The transportation fees charged under these arrangements are either contractual or regulated by governmental agencies, including the FERC. Revenues associated with these arrangements are recognized when volumes have been delivered.

Under our crude oil terminaling agreements, we charge customers for crude oil storage based on the number of days a customer has volumes in storage multiplied by a contractual storage rate. Under these contracts, revenue is recognized ratably over the length of the storage period. With respect to storage capacity reservation agreements, we collect a fee for reserving storage capacity for customers at our terminals. Under these agreements, revenue is recognized ratably over the specified reservation period. In addition, we charge our customers throughput (or "pumpover") fees based on volumes withdrawn from our terminals. Crude oil storage revenues are recognized ratably over the length of the storage period. Revenues are also generated from fee-based trade documentation services and are recognized as services are completed.

Our crude oil marketing activities generate revenues from the sale and delivery of crude oil obtained from producers or on the open market. These sales contracts generally settle with the physical delivery of crude oil to customers. In general, the sales prices referenced in these contracts are market-based and may include pricing differentials for such factors as delivery location.

Offshore Pipelines & Services

Our Offshore Pipelines & Services include our: (i) offshore natural gas pipelines; (ii) offshore Gulf of Mexico crude oil pipeline systems; and (iii) six multi-purpose offshore hub platforms which serve production areas including some of the most active drilling and development regions in the Gulf of Mexico.

Revenues from our offshore pipelines are derived from fee-based agreements whereby the customer is charged a fee per unit of volume gathered or transported (typically per MMBtu of natural gas or per barrel of crude oil) multiplied by the volume delivered. Revenues associated with these fee-based contracts and tariffs are recognized when volumes have been delivered.

Revenues from offshore platform services generally consist of demand fees and commodity charges. Revenues from platform services are recognized in the period the services are provided. Demand fees represent charges to customers served by our offshore platforms regardless of the volume the customer actually delivers to the platform. Revenues from commodity charges are based on a fixed-fee per unit of volume delivered to the platform (typically per MMcf of natural gas or per barrel of crude oil) multiplied by the total volume of each product delivered. Contracts for platform services often include both demand fees and commodity charges, but demand fees generally expire after a contractually fixed period of time and in some instances may be subject to cancellation by customers. Our Independence Hub offshore platform earns a significant amount of demand revenues. The Independence Hub platform will earn \$54.6 million of demand fees annually through March 2012.

Petrochemical & Refined Products Services

Our Petrochemical & Refined Products Services consist of: (i) propylene fractionation plants and related activities; (ii) butane isomerization facilities; (iii) an octane enhancement facility; (iv) refined products pipelines, including our Products Pipeline System, and related activities; and (v) marine transportation assets and other services.

Our propylene fractionation and butane isomerization facilities generate revenues through fee-based arrangements, which typically include a base-processing fee per gallon (or other unit of measurement) subject to adjustment for changes in natural gas, electricity and labor costs, which are the primary costs of propylene fractionation and butane isomerization. Revenues resulting from such agreements are recognized in the period the services are provided.

Our petrochemical marketing activities generate revenues from the sale and delivery of products obtained through our propylene fractionation activities and purchases of petrochemical products from third parties on the open market. Revenues from these sales contracts are recognized when such products are delivered to customers. In general, we sell our petrochemical products at market-based prices, which may include pricing differentials for such factors as delivery location.

Our refined products pipelines, including our Products Pipeline System, generate revenues through fee-based contracts or tariffs as customers are billed a fixed fee per barrel of liquids transported multiplied by the volume delivered. Transportation fees charged under these arrangements are either contractual or regulated by governmental agencies, including the FERC. Revenues associated with these fee-based contracts and tariffs are recognized when volumes have been delivered. Revenues from our refined products storage facilities are based on the number of days a customer has volumes in storage multiplied by a contractual storage rate. Under these contracts, revenue is recognized ratably over the length of the storage period. Revenues from product terminaling activities are recorded in the period such services are provided. Customers are typically billed a fee per unit of volume loaded.

Revenue is also generated from the provision of inland and offshore transportation of refined products, crude oil, condensate, asphalt, heavy fuel oil and other heated oil products via tow boats and tank barges. Under our marine services transportation contracts, revenue is recognized over the transit time of individual tows as determined on an individual contract basis, which is generally less than ten days in duration. Revenue from these contracts is typically based on set day rates or a set fee per cargo movement. Most of the marine services transportation contracts include escalation provisions to recover increased operating costs such as incremental increases in labor. The costs of fuel, substantially all of which is a pass through expense, and other specified operational fees and costs are directly reimbursed by the customer under most of the contracts.

The results of operations from the distribution of lubrication oils and specialty chemicals and the bulk transportation of fuels are dependent on the sales price or transportation fees that we charge our customers. Revenue is recognized for sales transactions and transportation arrangements when the product is delivered.

NOTE 5. EQUITY-BASED AWARDS

The following table summarizes the expense we recognized in connection with equity-based awards for the periods presented:

	FOR YEAR ENDED DECEMBER 31,			
	2009	2008	2007	
Restricted unit awards (1)	\$ 12.9	\$ 10.9	\$ 8.7	
Unit option awards (1)	1.8	0.7	4.5	
Unit appreciation rights (2)	0.1	_	0.1	
Phantom units (2)	0.2	(0.5)	2.3	
Profits interests awards (1)	8.5	6.3	4.3	
Total compensation expense	\$ 23.5	\$ 17.4	\$ 19.9	

- (1) Accounted for as equity-classified awards.
- (2) Accounted for as liability-classified awards.

The fair value of an equity-classified award (e.g., a restricted unit award) is amortized to earnings on a straight-line basis over the requisite service or vesting period. Compensation expense for liability-classified awards (e.g., unit appreciation rights ("UARs")) is recognized over the requisite service or vesting period of an award based on the fair value of the award remeasured at each reporting period. Liability-classified awards are settled in cash upon vesting.

At December 31, 2009, our active long-term incentive plans are the Enterprise Products 1998 Long-Term Incentive Plan ("1998 Plan"), the TEPPCO 1999 Phantom Unit Retention Plan ("1999 Plan"), the Enterprise Products 2006 TPP Long-Term Incentive Plan ("2006 Plan") and the Amended and Restated 2008 Enterprise Products Long-Term Incentive Plan ("2008 Plan"). Two plans were dissolved during 2009: TEPPCO 2000 Long-Term Incentive Plan ("2000 Plan") and TEPPCO 2005 Phantom Unit Plan ("2005 Plan").

The 1998 Plan provides for awards of our common units and other rights to our non-employee directors and to employees of EPCO and its affiliates providing services to us. Awards under the 1998 Plan may be granted in the form of unit options, restricted units, phantom units, UARs and distribution equivalent rights ("DERs"). Up to 7,000,000 of our common units may be issued as awards under the 1998 Plan. After giving effect to awards granted under the plan through December 31, 2009, a total of 652,543 additional common units could be issued.

The 1999 Plan provided key employees of EPCO who work on our behalf with phantom unit awards. This plan terminated in January 2010.

The 2006 Plan currently provides for awards of our common units (formerly of TEPPCO units) and other rights to our non-employee directors and to employees of EPCO and its affiliates providing services to us. Awards under the 2006 Plan may be granted in the form of unit options, restricted units, phantom units, UARs and DERs. Effective upon the consummation of the TEPPCO Merger (see Note 1), we assumed the vested and unvested options, restricted units and UAR awards outstanding on October 26, 2009 under the 2006 Plan and converted them into our options, restricted units and UAR awards based on the TEPPCO Merger exchange ratio. The vesting terms of each award and other provisions of the plan remain unchanged.

The 2008 Plan provides for awards of our common units and other rights to our non-employee directors and to consultants and employees of EPCO and its affiliates providing services to us. Awards under the 2008 Plan may be granted in the form of unit options, restricted units, phantom units, UARs and DERs. Up to 10,000,000 of our common units may be issued as awards under the 2008 Plan. After giving effect to awards granted under the plan through December 31, 2009, a total of 7,865,000 additional common units could be issued.

An allocated portion of the fair value of these long-term incentive plan equity-based awards is charged to us under the ASA (see Note 15 for a general description of the ASA with EPCO). With the exception of certain amounts recorded in connection with EPCO Unit, as defined later in this note, we are not responsible for reimbursing EPCO for any expenses associated with such awards. We recognize an expense for our allocated share of the grant date fair value of such awards, with an offsetting amount recorded in equity. Beginning in February 2009, the ASA was amended to provide that we and other affiliates of EPCO will reimburse EPCO for our allocated share of distributions of cash or securities made to the Class B limited partners of EPCO Unit. Our reimbursements to EPCO during 2009 in connection with EPCO Unit were \$0.5 million.

On December 10, 2009, the board of directors of DEP GP unanimously approved a resolution adopting both the 2010 Duncan Energy Partners L.P. Long-Term Incentive Plan ("2010 Plan") and the DEP Unit Purchase Plan ("DEP EUPP"). The 2010 Plan provides for awards of options to purchase Duncan Energy Partners' common units, restricted common units, UARs, phantom units and DERs to employees, directors or consultants providing services to Duncan Energy Partners. The DEP EUPP provides eligible employees the opportunity to purchase common units at a discount through withholdings from eligible compensation. On December 30, 2009, the action taken by the board of directors of DEP GP regarding the plans was approved by written consent of EPO, which held approximately 58.6% of Duncan Energy Partners' outstanding common units as of that date. Because EPO held a majority of Duncan Energy Partners' common units as of December 30, 2009, no other votes were necessary to adopt the plans. In February 2010, Duncan Energy Partners filed a registration statement with the Securities and Exchange Commission ("SEC") authorizing the issuance of up to 500,000 common units in connection with the 2010 Plan and 500,000 common units in connection with the DEP EUPP. The plans became effective on February 11, 2010.

Restricted Unit Awards

Restricted unit awards allow recipients to acquire common units of Enterprise Products Partners (at no cost to the recipient) once a defined vesting period expires, subject to customary forfeiture provisions. The restrictions on such awards generally lapse four years from the date of grant. The fair value of restricted units is based on the market price per unit of the underlying security on the date of grant. Compensation expense is recognized based on the grant date fair value, net of an allowance for estimated forfeitures. As used in the context of our long-term incentive plans, the term "restricted unit" represents a time-vested unit. Such awards are non-vested until the required service period expires.

The following table summarizes information regarding our restricted unit awards for the periods indicated:

	NUMBER OF UNITS	WEIGHTED- AVERAGE GRANT DATE FAIR VALUE PER UNIT (1)
Restricted units at December 31, 2006	1,105,237	\$ 24.79
Granted (2)	738,040	\$ 30.64
Vested	(4,884)	\$ 25.28
Forfeited	(36,800)	\$ 23.51
Settled (3)	(113,053)	\$ 23.24
Restricted units at December 31, 2007	1,688,540	\$ 27.23
Granted (4)	766,200	\$ 30.73
Vested	(285,363)	\$ 23.11
Forfeited	(88,777)	\$ 26.98
Restricted units at December 31, 2008	2,080,600	\$ 29.09
Granted (5)	1,025,650	\$ 24.89
Vested	(281,500)	\$ 26.70
Forfeited	(411,884)	\$ 28.37
Awards assumed in connection with TEPPCO Merger	308,016	\$ 27.64
Restricted units at December 31, 2009	2,720,882	\$ 27.70

- (1) Determined by dividing the aggregate grant date fair value of awards before an allowance for forfeitures by the number of awards issued. With respect to restricted unit awards assumed in connection with the TEPPCO Merger, the weighted-average grant date fair value per unit was determined by dividing the aggregate grant date fair value of the assumed awards before an allowance for forfeitures by the number of awards assumed.
- (2) Aggregate grant date fair value of restricted unit awards issued during 2007 was \$22.6 million based on grant date market prices of our common units ranging from \$28.00 to \$31.83 per unit. Estimated forfeiture rates ranging between 4.6% and 17% were applied to these awards.
- (3) Reflects the settlement of restricted units in connection with the resignation of our general partner's former chief executive officer.
- (4) Aggregate grant date fair value of restricted unit awards issued during 2008 was \$23.5 million based on grant date market prices of our common units ranging from \$25.00 to \$32.31 per unit. An estimated forfeiture rate of 17% was applied to these awards.
- (5) Aggregate grant date fair value of restricted unit awards issued during 2009 was \$25.5 million based on grant date market prices of our common units ranging from \$20.08 to \$28.73 per unit. Estimated forfeiture rates ranging between 4.6% and 17% were applied to these awards.

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 the respective issuer. Since restricted units are issued securities, such distributions are reflected as a component of cash distributions to partners as shown on our Statements of Consolidated Cash Flows. The following table presents cash distributions with respect to our restricted units and supplemental information regarding our restricted units for the periods indicated:

	FOR YEAR ENDED DECEMBER 31,			
	2009	2008	2007	
Cash distributions paid to restricted unit holders	\$ 5.2	\$ 3.9	\$ 2.6	
Total fair value of restricted unit awards vesting during period	7.5	6.6	0.1	

On a gross basis, the total unrecognized compensation cost of such awards was \$37.9 million at December 31, 2009, of which our share is currently estimated to be \$35.7 million. We expect to recognize our share of the unrecognized compensation cost for these awards over a weighted-average period of 2.3 years.

Unit Option Awards

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

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

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

In order to fund its unit option-related obligations, EPCO may purchase common units at fair value either in the open market or directly from us. When employees exercise unit options, we reimburse EPCO for the cash difference between the strike price paid by the employee and the actual purchase price paid by EPCO for the units issued to the employee.

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

	NUMBER OF UNITS	WEIGHTED- AVERAGE STRIKE PRICE (DOLLARS/ UNIT)	WEIGHTED- AVERAGE REMAINING CONTRACTUAL TERM (IN YEARS)	AGGREGATE Intrinsic Value (1)
Outstanding at December 31, 2006	2,416,000	\$ 23.32		
Granted (2)	895,000	30.63		
Exercised	(256,000)	19.26		
Settled or forfeited (3)	(740,000)	24.62		
Outstanding at December 31, 2007	2,315,000	26.18		
Granted (4)	795,000	30.93		
Exercised	(61,500)	20.38		
Forfeited	(85,000)	26.72		
Outstanding at December 31, 2008	2,963,500	27.56		
Granted (5)	1,460,000	23.46		
Exercised	(261,000)	19.61		
Forfeited	(930,540)	26.69		
Awards assumed in connection with TEPPCO Merger	593,960	26.12		
Outstanding at December 31, 2009 (6)	3,825,920	26.52	4.6	\$ 2.8
Options exercisable at:				
December 31, 2007	335,000	\$ 22.06	4.0	\$ 3.3
December 31, 2008	548,500	\$ 21.47	4.1	\$ —
December 31, 2009 (6)	447,500	\$ 25.09	4.8	\$ 2.8

- (1) Aggregate intrinsic value reflects fully vested unit options at the date indicated.
- (2) Aggregate grant date fair value of these unit options issued during 2007 was \$2.4 million based on the following assumptions: (i) a weighted-average grant date market price of our common units of \$30.63 per unit; (ii) expected life of options of 7.0 years; (iii) weighted-average risk-free interest rate of 4.8%; (iv) weighted-average expected distribution yield on our common units of 8.4%; and (v) weighted-average expected unit price volatility on our common units of 23.2%.
- (3) Includes the settlement of 710,000 options in connection with the resignation of our general partner's former chief executive officer.
- (4) Aggregate grant date fair value of these unit options issued during 2008 was \$1.9 million based on the following assumptions: (i) a grant date market price of our 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 our common units of 7.0%; and (v) expected unit price volatility on our common units of 19.8%. An estimated forfeiture rate of 17% was applied to awards granted during 2008.
- (5) Aggregate grant date fair value of these unit options issued during 2009 was \$8.1 million based on the following assumptions: (i) a weighted-average grant date market price of our common units of \$23.46 per unit; (ii) weighted-average expected life of options of 4.8 years; (iii) weighted-average risk-free interest rate of 2.1%; (iv) weighted-average expected distribution yield on our common units of 9.4%; and (v) weighted-average expected unit price volatility on our common units of 57.4%. An estimated forfeiture rate of 17% was applied to awards granted during 2009
- (6) We were committed to issue 3,825,920 and 2,963,500 of our common units at December 31, 2009 and 2008, respectively, if all outstanding options awarded (as of these dates) were exercised. Of the option awards outstanding at December 31, 2009, an additional 410,000, 712,280, 736,000 and 1,520,140 are exercisable in 2010, 2012, 2013 and 2014, respectively.

The following table presents supplemental information regarding our unit options:

	FOR YEAR ENDED DECEMBER 31,			
	2009	2008	2007	
Total intrinsic value of option awards exercised during period	\$ 2.4	\$ 0.6	\$ 3.0	
Cash received from EPCO in connection with the exercise of unit option awards	1.7	0.7	7.6	
Option-related reimbursements to EPCO	2.4	0.6	3.0	

On a gross basis, the total unrecognized compensation cost of such awards was \$7.3 million at December 31, 2009 of which our share is currently estimated to be \$6.3 million. We expect to recognize our share of the unrecognized compensation cost for these awards over a weighted-average period of 2.9 years.

Profits Interests Awards

As long-term incentive arrangements, EPCO has granted its key employees who perform services on behalf of us, EPCO and other affiliated companies, "profits interests" in several limited partnerships (the "Employee Partnerships"), all of which are private company affiliates of EPCO. At December 31, 2009, the Employee Partnerships are EPE Unit II, EPE Unit III, Enterprise Unit and EPCO Unit. TEPPCO Unit L.P. and TEPPCO Unit II L.P. were dissolved during 2009.

Profits interests awards entitle each holder to participate in the expected long-term appreciation in value of the equity securities owned by each Employee Partnership. The Employee Partnerships in which our named executive officers participate own either units of Enterprise GP Holdings or Enterprise Products Partners or a combination of both. The profits interests awards are subject to customary forfeiture provisions.

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

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

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

EMPLOYEE Partnership	DESCRIPTION OF ASSETS	INITIAL CLASS A CAPITAL BASE	CLASS A PARTNER PREFERRED RETURN	LIQUIDATION DATE (1)	GRANT DATE FAIR VALUE OF AWARDS	UNRECOGNIZED COMPENSATION COST
EPE Unit I	1,821,428 EPE units	\$51.0 million	4.50% to 5.725%	February 2016	\$21.5 million	\$12.1 million
EPE Unit II	40,725 EPE units	\$1.5 million	4.50% to 5.725%	February 2016	\$0.4 million	\$0.3 million
EPE Unit III	4,421,326 EPE units	\$170.0 million	3.80%	February 2016	\$42.8 million	\$30.8 million
Enterprise Unit	881,836 EPE units 844,552 EPD units	\$51.5 million	5.00%	February 2016	\$6.5 million	\$5.3 million
EPCO Unit	779,102 EPD units	\$17.0 million	4.87%	February 2016	\$8.1 million	\$6.5 million

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

The total unrecognized compensation cost of the profits interests awards was \$55.0 million at December 31, 2009 of which our share is currently estimated to be \$43.5 million. We expect to recognize our share of the unrecognized compensation cost for these awards over a weighted-average period of 6.1 years.

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

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

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

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

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

EMPLOYEE Partnership	EXPECTED Life of Award	RISK-FREE Interest rate	EXPECTED DISTRIBUTION YIELD	EXPECTED UNIT PRICE VOLATILITY
EPE Unit I	3 to 6 years	1.2% to 5.0%	3.0% to 6.7%	16.6% to 35.0%
EPE Unit II	4 to 6 years	1.6% to 4.4%	3.8% to 6.4%	18.7% to 31.7%
EPE Unit III	4 to 6 years	1.4% to 4.9%	4.0% to 6.4%	16.6% to 32.2%
Enterprise Unit	4 to 6 years	1.4% to 3.9%	4.5% to 8.4%	15.3% to 31.7%
EPCO Unit	4 to 6 years	1.6% to 2.4%	8.1% to 11.1%	27.0% to 50.0%

Phantom Units

Certain of our long-term incentive plans provide for the issuance of phantom unit awards. These awards are automatically redeemed for cash based on the fair value of the vested portion of phantom units at redemption dates in each award. The fair value of each phantom unit award is equal to the closing market price of the underlying security on the redemption date. Each participant is required to redeem their phantom units as they vest, which typically is three to four years from the date the award is granted. Our phantom units are accounted for as liability awards.

Certain of our long-term incentive plans also provide for the award of DERs in tandem with phantom unit awards. A DER entitles the participant to cash distributions equal to the product of the number of awards outstanding for the participant and the cash distribution rate per unit paid by the issuer to its unitholders. Such amounts are expensed when paid.

The following table presents additional information regarding our phantom unit awards for the periods indicated:

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	PHANTOM UNIT AWARDS ISSUED BY			
	ENTERPRISE PRODUCTS			
	TEPPC0	PARTNERS	TOTAL	
Phantom units at December 31, 2006	154,479	_	154,479	
Granted	259	_	259	
Vested	(13,533)	_	(13,533)	
Settled or forfeited	(13,800)	_	(13,800)	
Phantom units at December 31, 2007	127,405	_	127,405	
Granted	1,698	4,400	6,098	
Vested	(58, 168)	_	(58, 168)	
Settled or forfeited	(1,600)	_	(1,600)	
Phantom units at December 31, 2008	69,335	4,400	73,735	
Granted	124	6,200	6,324	
Vested	(61,519)	_	(61,519)	
Settled or forfeited	(4,447)	_	(4,447)	
Awards assumed in connection with TEPPCO Merger	(3,493)	4,327	834	
Phantom units at December 31, 2009		14,927	14,927	

	FOR YEAR ENDED DECEMBER 31,			
	2009	2008	2007	
Accrued liability for phantom unit awards, at end of period	\$ 0.2	\$ 1.2	\$ 4.5	
Liabilities paid for phantom unit awards	1.2	2.5	0.6	

At December 31, 2009, only the 2008 Plan and the 1999 Plan had significant phantom units outstanding. These awards will settle as follows: 4,327 in 2010, 4,400 in 2011 and 6,200 in 2012. The 2000 Plan and 2005 Plan also issued phantom units, all of which had vested and settled prior to December 31, 2009. The 3,472 phantom units outstanding under the 1999 Plan were settled in January 2010 and the plan terminated.

Unit Appreciation Rights

UARs entitle a participant to receive a cash payment on the vesting date equal to the excess, if any, of the fair market value of the underlying security (determined as of a future vesting date) over the grant date fair value of the award. UARs are accounted for as liability awards. The following table presents additional information regarding our UARs for the periods indicated:

		UAKS 155	UED B.I	
	TEPPCO	ENTERPRISE PRODUCTS PARTNERS	EPE	TOTAL
UARs at December 31, 2006	_	_	_	_
Granted	404,704	_	90,000	494,704
Settled or forfeited	(2,756)	_	_	(2,756)
UARs at December 31, 2007	401,948	_	90,000	491,948
Granted	29,429	_	_	29,429
UARs at December 31, 2008	431,377	_	90,000	521,377
Settled or forfeited	(166, 217)	(186,614)	_	(352,831)
Awards assumed in connection with the TEPPCO Merger	(265,160)	328,810	_	63,650
UARs at December 31, 2009		142,196	90,000	232,196

	AT DECEMBER 31,				
	2009	2008	2007		
Accrued liability for UARs	\$ 0.3	\$ 0.1	\$ 0.1		

At December 31, 2009, 142,196 UARs had been granted under the 2006 Plan to certain employees of EPCO who work on our behalf. These awards are subject to five year cliff vesting requirements and are expected to settle in 2012. The grant date fair value with respect to these UARs is based on an Enterprise Products Partners' unit price of \$37.00. If the employee resigns prior to vesting, these UAR awards are forfeited.

Prior to the TEPPCO Merger, 95,654 UARs had been granted to the non-employee former directors of TEPPCO under the 2006 Plan. The awards were settled in October 2009 and \$0.1 million in cash was paid to the former directors.

The non-employee directors of DEP GP, the general partner of Duncan Energy Partners, have been granted UARs in the form of letter agreements. These liability awards are not part of any established long-term incentive plan of EPCO, Enterprise GP Holdings, Duncan Energy Partners or us. The compensation expense associated with these awards is recognized by DEP GP, which is our consolidated subsidiary. At December 31, 2009, there were a total of 90,000 outstanding UARs granted to non-employee directors of DEP GP that cliff vest in 2012. If a director resigns prior to vesting, his UAR awards are forfeited. The grant date fair value with respect to these UARs is based on an Enterprise GP Holdings' unit price of \$36.68.

NOTE 6. DERIVATIVE INSTRUMENTS, HEDGING ACTIVITIES AND FAIR VALUE MEASUREMENTS

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

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

- Changes in the fair value of a recognized asset or liability, or an unrecognized firm commitment: In a fair value hedge, gains and losses for both the derivative instrument and the hedged item are recognized in income during the period of change.
- Variable cash flows of a forecasted transaction: In a cash flow hedge, the effective portion of the hedge
 is reported in other comprehensive income or loss ("OCI") and is reclassified into earnings when the
 forecasted transaction affects earnings.
- Foreign currency exposure: A foreign currency hedge can be treated as either a fair value hedge or a cash flow hedge depending on the risk being hedged.

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

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

Interest Rate Derivative Instruments

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

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

HEDGED TRANSACTION	NUMBER AND TYPE OF DERIVATIVE EMPLOYED	NOTIONAL AMOUNT	PERIOD OF HEDGE	RATE SWAP	ACCOUNTING TREATMENT
Enterprise Products Partners:					
Senior Notes C	1 fixed-to-floating swap	\$100.0	1/04 to 2/13	6.4% to 2.8%	Fair value hedge
Senior Notes G	3 fixed-to-floating swaps	\$300.0	10/04 to 10/14	5.6% to 1.5%	Fair value hedge
Senior Notes P	7 fixed-to-floating swaps	\$400.0	6/09 to 8/12	4.6% to 2.7%	Fair value hedge
Duncan Energy Partners:					
Variable-interest rate borrowings	3 floating-to-fixed swaps	\$175.0	9/07 to 9/10	0.3% to 4.6%	Cash flow hedge

Changes in the fair value of the interest rate swaps and the related hedged items were recorded on the balance sheet with the offset recorded as interest expense. Cash flow hedges fix the interest rate paid on floating rate debt with the difference between the floating rate and fixed rate being recorded as an increase or decrease to interest expense. This combined activity resulted in an increase of interest expense of \$1.9 million and \$0.6 million for the years ended December 31, 2009 and 2008, respectively.

At times, we may use treasury lock derivative instruments to hedge the underlying U.S. treasury rates related to forecasted issuances of debt. As cash flow hedges, gains or losses on these instruments are recorded in OCI and amortized into earnings using the effective interest method over the estimated term of the underlying fixed-rate debt. During 2008, we terminated treasury locks with a combined notional amount of \$1.2 billion and recognized an aggregate loss of \$43.9 million in OCI related to these terminations.

During the year ended December 31, 2009, we entered into four forward starting interest rate swaps to hedge the underlying benchmark interest payments related to the forecasted issuances of debt.

HEDGED TRANSACTION	NUMBER AND TYPE OF DERIVATIVE EMPLOYED	NOTIONAL AMOUNT	PERIOD OF HEDGE	AVERAGE RATE LOCKED	ACCOUNTING TREATMENT
Future debt offering	1 forward starting swap	\$50.0	6/10 to 6/20	3.3%	Cash flow hedge
Future debt offering	3 forward starting swaps	\$250.0	2/11 to 2/21	3.6%	Cash flow hedge

Forward starting interest rate swaps are used to hedge the underlying benchmark interest payments related to the forecasted issuances of debt. The fair market value of the forward starting swaps was \$21.0 million at December 31, 2009. During January and February 2010, we entered into five additional forward starting swaps with a notional amount of \$50.0 million each. The period hedged by these five forward starting swaps is February 2012 through February 2022.

Commodity Derivative Instruments

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

	VOLUME (1)			
DERIVATIVE PURPOSE	CURRENT	LONG-TERM (2)	ACCOUNTING TREATMENT	
Derivatives designated as hedging instruments:				
Enterprise Products Partners:				
Natural gas processing:				
Forecasted natural gas purchases for plant thermal				
reduction ("PTR") (3)	17.8 Bcf	n/a	Cash flow hedge	
Forecasted NGL sales (4)	2.4 MMBbls	n/a	Cash flow hedge	
Octane enhancement:				
Forecasted purchases of NGLs	2.0 MMBbls	n/a	Cash flow hedge	
NGLs inventory management	0.1 MMBbls	n/a	Cash flow hedge	
Forecasted sales of octane enhancement products	3.4 MMBbls	0.4 MMBbls	Cash flow hedge	
Natural gas marketing:				
Natural gas storage inventory management activities	3.5 Bcf	n/a	Fair value hedge	
NGL marketing:				
Forecasted purchases of NGLs and related hydrocarbon products	7.5 MMBbls	n/a	Cash flow hedge	
Forecasted sales of NGLs and related hydrocarbon products	8.0 MMBbls	n/a	Cash flow hedge	
Derivatives not designated as hedging instruments:				
Enterprise Products Partners:				
Natural gas risk management activities (5) (6)	359.2 Bcf	33.9 Bcf	Mark-to-market	
NGL risk management activities (6)	0.4 MMBbls	n/a	Mark-to-market	
Crude oil risk management activities (6)	3.5 MMBbls	n/a	Mark-to-market	
Duncan Energy Partners:				
Natural gas risk management activities (6)	2.2 Bcf	n/a	Mark-to-market	

- (1) Volume for derivatives designated as hedging instruments reflects the total amount of volumes hedged whereas volume for derivatives not designated as hedging instruments reflects the absolute value of derivative notional volumes.
- (2) The maximum term for derivatives included in the long-term column is December 2012.
- (3) PTR represents the British thermal unit equivalent of the NGLs extracted from natural gas by a processing plant, and includes the natural gas used as plant fuel to extract those liquids, plant flare and other shortages. See the discussion below for the primary objective of this strategy.
- (4) Excludes 5.4 MMBbls of additional hedges executed under contracts that have been designated as normal sales agreements under the FASB's derivative and hedging guidance. The combination of these volumes with the 2.4 MMBbls reflected as derivatives in the table above results in a total of 7.8 MMBbls of hedged forecasted NGL sales volumes, which corresponds to the 17.8 Bcf of forecasted natural gas purchase volumes for PTR.
- (5) Current and long-term volumes include approximately 109.5 and 12.6 Bcf, respectively, of physical derivative instruments that are predominantly priced at an index plus a premium or minus a discount.
- (6) Reflects the use of derivative instruments to manage risks associated with transportation, processing and storage assets.

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

Our three predominant hedging strategies are hedging natural gas processing margins, hedging anticipated future sales of NGLs, refined products and crude oil associated with volumes held in inventory and hedging the fair value of natural gas in inventory. The objective of our natural gas processing strategy is to hedge an amount of gross margin associated with the gas processing activities. We achieve this by using physical and financial instruments to lock in the prices of natural gas purchases used for PTR and NGL sales. This program consists of (i) the forward sale of a portion of our expected equity NGL production at fixed prices through December 2010, achieved through the use of forward physical sales and commodity derivative instruments, and (ii) the purchase of commodity derivative instruments with a notional amount determined by the amount of natural gas expected to be consumed as PTR in the production of such equity NGL production. The objective of our NGL, refined products and crude oil sales hedging program is to hedge anticipated future sales of inventory by locking in the sales price through the use of forward physical sales and commodity derivative instruments. The objective of our natural gas inventory hedging program is to hedge the fair value of natural gas currently held in inventory by locking in the sales price of the inventory through the use of commodity derivative instruments.

Foreign Currency Derivative Instruments

We are exposed to a nominal amount of foreign currency exchange risk in connection with our NGL and natural gas marketing activities in Canada. As a result, we could be adversely affected by fluctuations in currency rates between the U.S. dollar and Canadian dollar. In order to manage this risk, we may enter into foreign exchange purchase contracts to lock in the exchange rate. Prior to 2009, these derivative instruments were accounted for using mark-to-market accounting. Beginning with the first quarter of 2009, the long-term transactions (more than two months) are accounted for as cash flow hedges. Shorter term transactions are accounted for using mark-to-market accounting.

In 2008 and 2009 we were exposed to foreign currency exchange risk in connection with a term loan denominated in Japanese yen (see Note 12). We entered into this loan agreement in November 2008 and the loan matured in March 2009. The derivative instrument used to hedge this risk was accounted for as a cash flow hedge and was settled upon repayment of the loan.

At December 31, 2009, we had foreign currency derivative instruments outstanding with a notional amount of \$4.1 million Canadian dollars. The fair market value of these instruments was an asset of \$0.2 million at December 31, 2009.

Credit-Risk Related Contingent Features in Derivative Instruments

A limited number of our commodity derivative instruments include provisions related to credit ratings and/or adequate assurance clauses. A credit rating provision provides for a counterparty to demand immediate full or partial payment to cover a net liability position upon the loss of a stipulated credit rating. An adequate assurance clause provides for a counterparty to demand immediate full or partial payment to cover a net liability position should reasonable grounds for insecurity arise with respect to contractual performance by either party. At December 31, 2009, the aggregate fair value of our over-the-counter derivative instruments in a net liability position was \$7.7 million, approximately \$6.1 million of which was subject to a credit rating contingent feature. If our credit ratings were downgraded to Ba2/BB, approximately \$1.1 million would be payable as a margin deposit to the counterparties, and if our credit ratings were downgraded to Ba3/BB- or below, approximately \$6.1 million would be payable as a margin deposit to the counterparties. Currently, no margin is required to be deposited. The potential for derivatives with contingent features to enter a net liability position may change in the future as positions and prices fluctuate.

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

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

		ASSET	DERIVATIVES		LIABILITY DERIVATIVES			
	DECEMBER 3	31, 2009	DECEMBER	31, 2008	DECEMBER 31	, 2009	DECEMBER 31, 2008	
	BALANCE Sheet Location	FAIR VALUE	BALANCE Sheet Location	FAIR VALUE	BALANCE SHEET LOCATION	FAIR VALUE	BALANCE SHEET LOCATION	FAIR VALUE
Derivatives designated as hedging inst	ruments							
Interest rate derivatives	Derivative assets	\$ 32.7	Derivative assets	\$ 7.8	Derivative liabilities	\$ 5.5	Derivative liabilities	\$ 5.9
Interest rate derivatives	Other assets	31.8	Other assets	38.9	Other liabilities	2.2	Other liabilities	3.9
Total interest rate derivatives		64.5	_	46.7		7.7	_	9.8
Commodity derivatives	Derivative assets	52.0	Derivative assets	150.6	Derivative liabilities	62.6	Derivative liabilities	253.5
Commodity derivatives	Other assets	0.5	Other assets		Other liabilities	1.8	Other liabilities	0.2
Total commodity derivatives (1)		52.5		150.6		64.4	_	253.7
Foreign currency derivatives (2)	Derivative assets	0.2	Derivative assets	9.3	Derivative liabilities		Derivative liabilities	
Total derivatives designated as hedging instruments		\$ 117.2	=	\$ 206.6		\$ 72.1	=	\$ 263.5
Derivatives not designated as hedging	instruments_							
Commodity derivatives	Derivative assets	\$ 28.9	Derivative assets	\$ 50.9	Derivative liabilities	\$ 24.9	Derivative liabilities	\$ 43.4
Commodity derivatives	Other assets	2.0	Other assets		Other liabilities	2.7	Other liabilities	
Total commodity derivatives		30.9		50.9		27.6		43.4
Foreign currency derivatives	Derivative assets		Derivative assets		Derivative liabilities		Derivative liabilities	0.1
Total derivatives not designated as hedging instruments		\$ 30.9	_	\$ 50.9		\$ 27.6	=	\$ 43.5

Represents commodity derivative transactions that either have not settled or have 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.

Relates to the hedging of our exposure to fluctuations in the foreign currency exchange rate related to our Canadian NGL marketing subsidiary.

The following tables present the effect of our derivative instruments designated as fair value hedges on our Statements of Consolidated Operations for the periods indicated:

DERIVATIVES IN FAIR VALUE HEDGING RELATIONSHIPS	LOCATION	GAIN (LOSS) RECOGNIZED IN INCOME ON DERIVATIVE		
		FOR YEAR ENDED DECEMBER 31,		
		2009	2008	
Interest rate	Interest expense	\$ (8.8)	\$ 31.2	
Commodity	Revenue	1.8	_	
Total		\$ (7.0)	\$ 31.2	
DERIVATIVES IN FAIR VALUE HEDGING RELATIONSHIPS	LOCATION		RECOGNIZED IN HEDGED ITEM	
		FOR YEAR ENDE	D DECEMBER 31,	
		2009	2008	
Interest rate	Interest expense	\$ 3.2	\$ (31.2)	
Commodity	Revenue	(1.3)	_	
Total		\$ 1.9	\$ (31.2)	

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

DERIVATIVES IN CASH FLOW

CHANGE IN VALUE RECOGNIZED

IN OCI ON DERIVATIVE

HEDGING R	ELATIONSHIPS	(EFFECTIVE	PORTION)
		FOR YEAR ENDED	DECEMBER 31,
		2009	2008
Interest rate derivatives		\$ 18.6	\$ (52.0)
Commodity derivatives – Reve	nue	(34.8)	(34.8)
Commodity derivatives – Oper	ating costs and expenses	(144.8)	(135.4)
Foreign currency derivatives		(10.2)	9.3
Total		\$ (171.2)	\$ (212.9)
DERIVATIVES IN CASH FLOW		RECLASSIFIE	GAIN/(LOSS) Ed from Aoci
HEDGING RELATIONSHIPS	LOCATION		FECTIVE PORTION)
			D DECEMBER 31,
		2009	2008
Interest rate derivatives	Interest expense	\$ (10.8)	\$ 1.1
Commodity derivatives	Revenue	(61.0)	(56.7)
Commodity derivatives	Operating costs and expenses	(233.2)	(39.6)
Total		\$ (305.0)	\$ (95.2)
DERIVATIVES IN CASH FLOW HEDGING RELATIONSHIPS	LOCATION	RECOGNIZED	F GAIN/(LOSS) IN INCOME ON TION OF DERIVATIVE
			D DECEMBER 31,
		2009	2008
Interest rate derivatives	Interest expense	\$ 0.1	\$ (3.6)
Commodity derivatives	Revenue	0.2	_
Commodity derivatives	Operating costs and expenses	(0.1)	(1.7)
Foreign currency derivatives			(0.1)
Total		\$ 0.2	\$ (5.4)

Over the next twelve months, we expect to reclassify \$10.8 million of AOCI attributable to interest rate derivative instruments into earnings as an increase to interest expense. Likewise, we expect to reclassify \$0.8 million of AOCI attributable to commodity derivative instruments into earnings, \$0.2 million as an increase in operating costs and expenses and \$1.0 million as an increase in revenues.

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

DERIVATIVES NOT DESIGNATED AS HEDGING INSTRUMENTS) RECOGNIZED IN DN DERIVATIVE DED DECEMBER 31.
		2009	2008
Commodity derivatives	Revenue	\$ 40.7	\$ 39.3
Commodity derivatives	Operating costs and expenses	_	(7.6)
Foreign currency derivatives	Other expense	(0.1)	(0.1)
Total		\$ 40.6	\$ 31.6

Fair Value Measurements

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

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

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

- Level 1 fair values are based on quoted prices, which are available in active markets for identical assets or liabilities as of the measurement date. Active markets are defined as those in which transactions for identical assets or liabilities occur with sufficient frequency so as to provide pricing information on an ongoing basis (e.g., the New York Mercantile Exchange). Our Level 1 fair values primarily consist of financial assets and liabilities such as exchange-traded commodity derivative instruments.
- Level 2 fair values are based on pricing inputs other than quoted prices in active markets (as reflected in Level 1 fair values) and are either directly or indirectly observable as of the measurement date. Level 2 fair values include instruments that are valued using financial models or other appropriate valuation methodologies. Such financial models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, the time value of money, volatility factors, current market and contractual prices for the underlying instruments and other relevant economic measures. Substantially all of these assumptions are: (i) observable in the marketplace throughout the full term of the instrument; (ii) can be derived from observable data; or (iii) are validated by inputs other than quoted prices (e.g., interest rate and yield curves at commonly quoted intervals). Our Level 2 fair values primarily consist of commodity derivative instruments such as forwards, swaps and other instruments transacted on an exchange or over the counter. The fair values of these derivatives are based on observable price quotes for similar products and locations. The value of our interest rate derivatives are valued by using appropriate financial models with the implied forward London Interbank Offered Rate ("LIBOR") yield curve for the same period as the future interest swap settlements.
- Level 3 fair values are based on unobservable inputs. Unobservable inputs are used to measure fair value to the extent that observable inputs are not available, thereby allowing for situations in which there is little, if any, market activity for the asset or liability at the measurement date. Unobservable inputs reflect the reporting entity's own ideas about the assumptions that market participants would use in pricing an asset or liability (including assumptions about risk). Unobservable inputs are based on the best information available in the circumstances, which might include the reporting entity's internally developed data. The reporting entity must not ignore information about market participant assumptions that is reasonably available without undue cost and effort. Level 3 inputs are typically used in connection with internally developed valuation methodologies where management makes its best estimate of an instrument's fair value. Our Level 3 fair values largely consist of ethane, normal butane and natural gasoline-based contracts with a range of two to 12 months in term. We rely on price quotes from reputable brokers in the marketplace who publish price quotes on certain products. Whenever possible, we compare these prices to other reputable brokers for the same product in the same market. These prices, combined with our forward transactions, are used in our model to determine the fair value of such instruments.

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

	AT DECEMBER 31, 2009							
	LE	VEL 1	LE	VEL 2	LE	VEL 3	T	OTAL
Financial assets:								
Interest rate derivative instruments	\$	_	\$	64.5	\$	_	\$	64.5
Commodity derivative instruments		14.6		34.4		34.4		83.4
Foreign currency derivative instruments				0.2	_			0.2
Total	\$	14.6	\$	99.1	\$	34.4	\$	148.1
Financial liabilities:								
Interest rate derivative instruments	\$	_	\$	7.7	\$	_	\$	7.7
Commodity derivative instruments		17.1	·	46.2	·	28.7	·	92.0
Total	\$	17.1	\$	53.9	\$	28.7	\$	99.7
			AT	DECEMBI	ER 31, 2	2008		
	LE	VEL 1	LE	VEL 2	LE	VEL 3	T	OTAL
Financial assets:								
Commodity derivative instruments	\$	4.0	\$	164.7	\$	32.8	\$	201.5
Foreign currency derivative instruments				9.3				9.3
Interest rate derivative instruments		_		46.7		_		46.7
Total	\$	4.0	\$	220.7	\$	32.8	\$	257.5
Financial liabilities:								
		7 1	Ф	289.6	\$	0.4	\$	297.1
Commodity derivative instruments	\$	7.1	Φ	209.0	Φ			
Commodity derivative instruments Foreign currency derivative instruments	\$	/.1 —	Ф	0.1	Φ	_	Ψ	0.1
	\$	/.1 	Φ		Φ	— —	Ψ	0.1 9.8
Foreign currency derivative instruments	\$ 	7.1	· ·	0.1	* *	0.4		

The following table sets forth a reconciliation of changes in the fair value of our Level 3 financial assets and liabilities for the periods presented:

	FOR YEAR ENDED DECEMBER 31,			
	2009	2008		
Balance, January 1	\$ 32.4	\$ (5.0)		
Total gains (losses) included in:				
Net income (1)	27.0	(34.6)		
Other comprehensive income (loss)	(21.8)	37.2		
Purchases, issuances, settlements	(26.8)	34.8		
Transfer out of Level 3	(5.1)	_		
Balance, December 31	\$ 5.7	\$ 32.4		

⁽¹⁾ There were unrealized losses of \$5.2 million and gains of \$0.2 million included in these amounts for the years ended December 31, 2009 and 2008, respectively.

Nonfinancial Assets and Liabilities

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

	LEVEL 3	IMPAIRMENT Charges
Property, plant and equipment (see Note 8)	\$ 29.6	\$ 29.4
Intangible assets (see Note 11)	0.6	0.6
Goodwill (see Note 11)	_	1.3
Other current assets	1.2	2.2
Total	\$ 31.4	\$ 33.5

Using appropriate valuation techniques, we adjusted the carrying value of certain assets to \$31.4 million and recorded non-cash impairment charges of \$33.5 million during 2009. These charges are reflected in operating costs and expenses for the year ended December 31, 2009 and have been allocated to property, plant and equipment, intangible assets, goodwill and other current assets. During 2009, impairments primarily resulted from: (i) reduced levels of throughput volumes at certain river terminals and the indefinite suspension of three new proposed river terminals; (ii) reduced throughput levels at a natural gas processing plant; (iii) the cancellation of a compressor station project; and (iv) the determination that a storage cavern and certain marine barges were obsolete. Our fair value estimates were based primarily on an evaluation of the future cash flows associated with each asset.

NOTE 7. INVENTORIES

Our inventory amounts were as follows at the dates indicated:

	DECEMB	DECEMBER 31,		
	2009	2008		
Working inventory (1)	\$ 466.4	\$ 188.1		
Forward sales inventory (2)	245.5	216.9		
Total inventory	\$ 711.9	\$ 405.0		

- (1) Working inventory is comprised of inventories of natural gas, NGLs, crude oil, refined products, lubrication oils and certain petrochemical products that are either available-for-sale or used in the provision for services.
- (2) Forward sales inventory consists of identified natural gas, NGL, refined product and crude oil volumes dedicated to the fulfillment of forward sales contracts. In general, the increase in volumes dedicated to forward physical sales contracts improves the overall utilization and profitability of our fee-based assets. The cash invested in forward sales NGL inventories is expected to be recovered within the next twelve months as physical delivery from inventory occurs.

In those instances where we take ownership of inventory volumes through percent-of-liquids contracts and similar arrangements (as opposed to actually purchasing volumes for cash from third parties, see Note 4), these volumes are valued at market-based prices during the month in which they are acquired.

Due to fluctuating commodity prices, we recognize LCM adjustments when the carrying value of our inventories exceeds their net realizable value. These non-cash charges are a component of cost of sales in the period they are recognized and generally affect our segment operating results in the following manner:

- Write-downs of NGL inventories are recorded as an expense related to our NGL marketing activities within our NGL Pipelines & Services business segment;
- Write-downs of natural gas inventories are recorded as an expense related to our natural gas pipeline operations within our Onshore Natural Gas Pipelines & Services business segment;
- Write-downs of crude oil inventories are recorded as an expense related to our crude oil operations within our Onshore Crude Oil Pipelines & Services business segment; and

Write-downs of petrochemical, refined products and related inventories are recorded as an expense related
to our petrochemical and refined products marketing activities or octane additive production business, as
applicable, within our Petrochemical & Refined Products Services business segment.

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

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

		FOR YEAR ENDED DECEMBER 31,					
	2009 2008 2007		2007				
Cost of sales (1)	\$	20,921.8	\$	31,204.8	\$	23,494.0	
LCM adjustments		6.3		63.0		14.1	

(1) Cost of sales is included in operating costs and expenses, as presented on our Statements of Consolidated Operations. The fluctuation in this amount yearto-year is primarily due to changes in energy commodity prices associated with our marketing activities.

NOTE 8. PROPERTY, PLANT AND EQUIPMENT

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

	ESTIMATED USEFUL LIFE	DECEN	IBER 31,
	IN YEARS	2009	2008
Plants and pipelines (1)	3-45 (5)	\$ 17,681.9	\$ 15,444.7
Underground and other storage facilities (2)	5-40 (6)	1,280.5	1,203.9
Platforms and facilities (3)	20-31	637.6	634.8
Transportation equipment (4)	3-10	60.1	50.9
Marine vessels	20-30	559.4	453.0
Land		82.9	76.5
Construction in progress		1,207.2	2,015.4
Total		21,509.6	19,879.2
Less accumulated depreciation		3,820.4	3,146.4
Property, plant and equipment, net		\$ 17,689.2	\$ 16,732.8

- (1) Plants and pipelines include processing plants; NGL, petrochemical, crude oil and natural gas pipelines; terminal loading and unloading facilities; office furniture and equipment; buildings; laboratory and shop equipment and related assets.
- (2) Underground and other storage facilities include underground product storage caverns, above ground storage tanks, water wells and related assets.
- (3) Platforms and facilities include offshore platforms and related facilities and other associated assets.
- (4) Transportation equipment includes vehicles and similar assets used in our operations.
- (5) In general, the estimated useful lives of major components of this category are as follows: processing plants, 20-35 years; pipelines and related equipment, 5-45 years; terminal facilities, 10-35 years; delivery facilities, 20-40 years; office furniture and equipment, 3-20 years; buildings, 20-40 years; and laboratory and shop equipment, 5-35 years.
- (6) In general, the estimated useful lives of major components of this category are as follows: underground storage facilities, 5-35 years; storage tanks, 10-40 years; and water wells, 5-35 years.

In August 2008, our wholly owned subsidiaries, together with Oiltanking Holding Americas, Inc. ("Oiltanking") formed the Texas Offshore Port System partnership ("TOPS"). Effective April 16, 2009, our wholly owned subsidiaries dissociated from TOPS. As a result, operating costs and expenses and net income for the year ended December 31, 2009 include a non-cash charge of \$68.4 million. This loss represents the forfeiture of our cumulative investment in TOPS through the date of dissociation and reflects our capital contributions to TOPS for construction in progress amounts.

TOPS was a consolidated subsidiary of ours prior to the dissociation. The effect of deconsolidation was to remove the accounts of TOPS, including Oiltanking's noncontrolling interest of \$33.4 million, from our books and records, after reflecting the \$68.4 million aggregate write-off of the investment. See Note 18 for information regarding expense amounts recognized during 2009 in connection with a settlement agreement involving TOPS.

In addition, we recorded \$21.0 million, \$4.3 million and \$4.1 million of non-cash asset impairment charges within our Petrochemical & Refined Products Services segment, Onshore Natural Gas Pipelines & Services segment and NGL Pipelines & Services segment, respectively, related to plant, property and equipment during the year ended December 31, 2009. See Note 6 for additional information regarding impairment charges.

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

	FOR YEAR ENDED DECEMBER 31,				
	2009	2008	2007		
Depreciation expense (1)	\$ 678.1	\$ 595.9	\$ 515.7		
Capitalized interest (2)	53.1	90.7	86.5		

- (1) Depreciation expense is a component of costs and expenses as presented in our Statements of Consolidated Operations.
- (2) Capitalized interest increases the carrying value of the associated asset and reduces interest expense during the period it is recorded.

We reviewed assumptions underlying the estimated remaining useful lives of certain of our assets during the first quarter of 2008. As a result of our review, effective January 1, 2008, we revised the remaining useful lives of these assets, most notably the assets that constitute our Texas Intrastate System. This revision increased the remaining useful life of such assets to incorporate recent data showing that natural gas reserves supporting throughput and processing volumes for these assets have changed since our original determination made in September 2004. These revisions will prospectively reduce our depreciation expense on assets having carrying values totaling \$2.72 billion as of January 1, 2008. On average, we extended the life of these assets by 3.1 years. As a result of this change in estimate, depreciation expense included in operating income and net income for the year ended December 31, 2008 decreased by approximately \$20.0 million, which increased our basic and diluted earnings per unit by \$0.04 from what it would have been absent the change.

Asset Retirement Obligations

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

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

ARO liability balance, December 31, 2007	\$ 42.2
Liabilities incurred	1.1
Liabilities settled	(8.2)
Revisions in estimated cash flows	4.7
Accretion expense	2.4
ARO liability balance, December 31, 2008	42.2
Liabilities incurred	0.5
Liabilities settled	(17.1)
Revisions in estimated cash flows	26.1
Accretion expense	3.1
ARO liability balance, December 31, 2009	\$ 54.8

The increase in our ARO liability balance during 2009 primarily reflects revised estimates of the cost to comply with regulatory abandonment obligations associated with our offshore facilities in the Gulf of Mexico. We incurred \$14.6 million of costs through December 31, 2009 as a result of ARO settlement activities associated with certain pipeline laterals and a platform located in the Gulf of Mexico.

Property, plant and equipment at December 31, 2009 and 2008 includes \$26.7 million and \$11.7 million, respectively, of asset retirement costs capitalized as an increase in the associated long-lived asset. The following table presents forecasted accretion expense associated with our AROs for the years presented:

2010	2011	2012	2013	2014
\$ 3.8	\$ 3.7	\$ 10	\$ 13	\$ 17

Certain of our unconsolidated affiliates have AROs recorded at December 31, 2009 and 2008 relating to contractual agreements and regulatory requirements. These amounts are immaterial to our financial statements.

NOTE 9. INVESTMENTS IN UNCONSOLIDATED AFFILIATES

We own interests in a number of related businesses that are accounted for using the equity method of accounting. We group our investments in unconsolidated affiliates according to the business segment to which they relate (see Note 14 for a general discussion of our business segments). The following table shows our investments in unconsolidated affiliates by business segment at the dates indicated:

	OWNERSHIP PERCENTAGE AT DECEMBER 31. —	DECEM	BER 31,
	2009	2009	2008
NGL Pipelines & Services:			
Venice Energy Service Company, L.L.C.	13.1%	\$ 32.6	\$ 37.7
K/D/S Promix, L.L.C.	50%	48.9	46.4
Baton Rouge Fractionators LLC	32.2%	22.2	24.2
Skelly-Belvieu Pipeline Company, L.L.C.	49%	37.9	36.0
Onshore Natural Gas Pipelines & Services:			
Evangeline (1)	49.5%	5.6	4.5
White River Hub, LLC	50%	26.4	21.4
Onshore Crude Oil Pipelines & Services:			
Seaway Crude Pipeline Company	50%	178.5	186.2
Offshore Pipelines & Services:			
Poseidon Oil Pipeline, L.L.C.	36%	61.7	60.2
Cameron Highway Oil Pipeline Company ("Cameron Highway")	50%	239.6	250.9
Deepwater Gateway, L.L.C.	50%	101.8	104.8
Neptune Pipeline Company, L.L.C.	25.7%	53.8	52.7
Nemo Gas Gathering Company, LLC ("Nemo")	33.9%	_	0.4
Petrochemical & Refined Products Services:			
Baton Rouge Propylene Concentrator, LLC	30%	11.1	12.6
Centennial Pipeline LLC ("Centennial")	50%	66.7	69.7
Other (2)	Varies	3.8	4.2
Total	=	\$ 890.6	\$ 911.9

⁽¹⁾ Evangeline refers to our ownership interests in Evangeline Gas Pipeline Company, L.P. and Evangeline Gas Corp., collectively.

⁽²⁾ Other unconsolidated affiliates include a 50% interest in a propylene pipeline extending from Mont Belvieu, Texas to La Porte, Texas and a 25% interest in a company that provides logistics communications solutions between petroleum pipelines and their customers.

On occasion, the price we pay to acquire an ownership interest in a company exceeds the underlying book value of the capital accounts we acquire. Such excess cost amounts are included within the carrying values of our investments in unconsolidated affiliates. The following table summarizes the unamortized excess cost amounts by business segment at the dates indicated:

	DECEMBER 31,	
	2009	2008
NGL Pipelines & Services	\$ 27.1	\$ 28.0
Onshore Crude Oil Pipelines & Services	20.4	21.1
Offshore Pipelines & Service	17.3	18.6
Petrochemical & Refined Products Services	4.0	7.9
Total	\$ 68.8	\$ 75.6

Such excess cost amounts were attributable to the underlying tangible and amortizable intangible assets of certain unconsolidated affiliates. We amortize such excess cost amounts as a reduction in equity earnings in a manner similar to depreciation. The following table presents our amortization of such excess cost amounts by business segment for the periods indicated:

	FOR YEAR ENDED DECEMBER 31,		
	2009	2008	2007
NGL Pipelines & Services	\$ 0.9	\$ 0.5	\$ 0.6
Onshore Crude Oil Pipelines & Services	0.7	0.7	0.7
Offshore Pipelines & Service	1.3	1.3	1.3
Petrochemical & Refined Products Services	3.9	4.3	5.3
Total	\$ 6.8	\$ 6.8	\$ 7.9

The following table presents our equity in income (loss) of unconsolidated affiliates by business segment for the periods indicated:

	FUR TEAR ENDED DECEMBER 31,		
	2009	2008	2007
NGL Pipelines & Services	\$ 11.3	\$ 1.4	\$ 7.1
Onshore Natural Gas Pipelines & Services	4.9	1.6	0.2
Onshore Crude Oil Pipelines & Services	9.3	11.7	2.6
Offshore Pipelines & Services	36.9	33.7	12.6
Petrochemical & Refined Products Services	(11.2)	(13.5)	(12.0)
Total	\$ 51.2	\$ 34.9	\$ 10.5

FOR VEAR ENDED DECEMBER 21

NGL Pipelines & Services

At December 31, 2009, our investees included in our NGL Pipelines & Services segment own: (i) a natural gas processing facility and related assets located in south Louisiana; (ii) an NGL fractionation facility and related storage and pipeline assets located in south Louisiana; (iii) an NGL fractionation facility located in south Louisiana; and (iv) a 572-mile pipeline that transports mixed NGLs to markets in southeast Texas.

During 2007, we sold an investment for approximately \$156.0 million in cash and recognized a gain of \$59.6 million, which is included in "Other, net" in our Statement of Consolidated Operations for the year ended December 31, 2007. The sale was required by the U.S. Federal Trade Commission in connection with ending its investigation into the acquisition of TEPPCO GP by privately held affiliates of EPCO in February 2005.

Onshore Natural Gas Pipelines & Services

At December 31, 2009, our investees included in our Onshore Natural Gas Pipelines & Services segment own: (i) a natural gas pipeline located in south Louisiana and (ii) a natural gas hub located in northwest Colorado that commenced operations in December 2008.

Onshore Crude Oil Pipelines & Services

At December 31, 2009, our investee included in our Onshore Crude Oil Pipelines & Services segment owns a pipeline that transports crude oil from a marine terminal located in Freeport, Texas, to Cushing, Oklahoma, and from a marine terminal located in Texas City, Texas, to refineries in the Texas City and Houston, Texas areas.

Offshore Pipelines & Services

At December 31, 2009, our investees included in our Offshore Pipelines & Services segment own: (i) a crude oil pipeline that gathers production from the outer continental shelf and deepwater areas of the Gulf of Mexico for delivery to onshore locations in south Louisiana; (ii) a crude oil pipeline that gathers production from deepwater areas of the Gulf of Mexico, primarily the South Green Canyon area, for delivery to refineries and terminals in southeast Texas; (iii) a crude oil and natural gas platform that processes production from the Marco Polo, K2, K2 North and Genghis Khan fields located in the South Green Canyon area of the Gulf of Mexico; and (iv) natural gas pipeline systems located in the Gulf of Mexico.

During 2007, Cameron Highway repaid two series of notes aggregating \$415.0 million using cash contributions from its partners. We funded our 50% share of the capital contributions using borrowings under EPO's Multi-Year Revolving Credit Facility. Cameron Highway incurred a \$14.1 million make-whole premium in connection with the repayment of its Series A notes.

Also during 2007, we evaluated our equity method investment in Nemo for impairment due to a decrease in throughput volumes primarily due to underperformance of certain fields and natural depletion. As a result of this evaluation, we recorded a \$7.0 million non-cash impairment charge that is a component of "Equity in income of unconsolidated affiliates" on our Consolidated Statement of Operations for the year ended December 31, 2007.

Petrochemical & Refined Products Services

At December 31, 2009, the investees included in our Petrochemical & Refined Products Services segment own: (i) a propylene fractionation facility located in south Louisiana; (ii) a propylene pipeline extending from Mont Belvieu, Texas to La Porte, Texas; and (iii) an interstate refined products pipeline extending from the upper Texas Gulf Coast to central Illinois that effectively loops our refined products pipeline system providing incremental transportation capacity into mid-continent markets.

Summarized Combined Financial Information of Unconsolidated Affiliates

The combined balance sheet information for the last two years and results of operations data for the last three years of our unconsolidated affiliates are summarized below:

	AT DECEMBER 31,		
	2009	2008	
BALANCE SHEET DATA:			
Current assets	\$ 201.0	\$ 240.8	
Property, plant and equipment, net	1,997.2	2,053.3	
Other assets	36.4	23.1	
Total assets	\$ 2,234.6	\$ 2,317.2	
Current liabilities	\$ 118.6	\$ 165.9	
Other liabilities	255.4	282.8	
Combined equity	1,860.6	1,868.5	
Total liabilities and combined equity	\$ 2,234.6	\$ 2,317.2	

	FOR YEAR ENDED DECEMBER 31,			
	2009	2008	2007	
NCOME STATEMENT DATA:				
Revenues	\$ 738.1	\$ 961.7	\$ 794.1	
Operating income	169.2	154.3	173.4	
Net income	155.9	136.1	110.5	

NOTE 10. BUSINESS COMBINATIONS

The following table presents our cash used for business combinations by segment for the periods indicated:

	FOR YEAR ENDED DECEMBER 31,					
	2009	2008	2007			
NGL Pipelines & Services	\$ 33.3	\$ 77.0	\$ 0.4			
Onshore Natural Gas Pipelines & Services	0.8	125.2	35.5			
Petrochemical & Refined Products Services	73.2	351.3				
Total cash used for business combinations	\$ 107.3	\$ 553.5	\$ 35.9			

The following table depicts the fair value allocation of assets acquired and liabilities assumed for our business combinations for the periods indicated:

	FOR YEAR ENDED DECEMBER 31,					
	2009	2008	2007			
Assets acquired in business combination:						
Current assets	\$ 1.4	\$ 6.6	\$ —			
Property, plant and equipment, net	115.9	549.6	44.5			
Intangible assets	0.3	92.5	(8.5)			
Other assets	(0.3)	0.4				
Total assets acquired	117.3	649.1	36.0			
Liabilities assumed in business combination:						
Current liabilities	0.3	(3.2)	_			
Long-term debt	_	(2.6)	_			
Other long-term liabilities	_	(109.5)	(1.2)			
Total liabilities assumed	0.3	(115.3)	(1.2)			
Total assets acquired plus liabilities assumed	117.6	533.8	34.8			
Noncontrolling interest acquired	10.3	_	_			
Fair value of 4,854,899 TEPPCO units	_	186.6				
Total cash used for business combinations	107.3	553.5	35.9			
Goodwill (1)	\$ —	\$ 206.3	\$ 1.1			

⁽¹⁾ See Note 11 for additional information regarding goodwill.

On a pro forma consolidated basis, our revenues, costs and expenses, operating income, net income attributable to Enterprise Products Partners L.P. and earnings per unit amounts would not have differed materially from those we actually reported for 2009, 2008 and 2007 due to the immaterial nature of our business combination transactions for those respective periods.

2009 Transactions

Our business combinations during 2009 primarily consisted of:

- the acquisition of certain rail and truck terminal facilities located in Mont Belvieu, Texas from Martin Midstream Partners LP for \$23.7 million in cash;
- the acquisition of tow boats and tank barges primarily based in Miami, Florida, with additional assets located in Mobile, Alabama and Houston, Texas from TransMontaigne Product Services Inc. for \$50.0 million in cash; and
- the acquisition of a majority interest in the Rio Grande Pipeline Company ("Rio Grande") purchased from HEP Navajo Southern L.P. for \$32.8 million in cash. Rio Grande owns an NGL pipeline system in Texas.

2008 Transactions

<u>Great Divide Gathering System Acquisition</u>. In December 2008, one of our subsidiaries, Enterprise Gas Processing, LLC, purchased a 100% membership interest in Great Divide Gathering, LLC ("Great Divide") for cash consideration of \$125.2 million. Great Divide was wholly owned by EnCana Oil & Gas ("EnCana").

The assets of Great Divide consist of a 32-mile natural gas gathering system, the Great Divide Gathering System, located in the Piceance Basin of northwest Colorado. The Great Divide Gathering System extends from the southern portion of the Piceance Basin, including production from EnCana's Mamm Creek field, to a pipeline interconnection with our Piceance Basin Gathering System. Volumes of natural gas originating on the Great Divide Gathering System are transported through our Piceance Creek Gathering System to our 1.7 Bcf/d Meeker natural gas treating and processing complex. A significant portion of these volumes are produced by EnCana and are dedicated to the Great Divide and Piceance Creek Gathering Systems for the life of the associated lease holdings.

Cenac and Horizon Acquisitions. In February 2008, TEPPCO entered the marine transportation business for refined products, crude oil and condensate through the purchase of assets from Cenac Towing Co., Inc., Cenac Offshore, L.L.C. and Mr. Arlen B. Cenac, Jr. (collectively "Cenac"). The aggregate value of total consideration TEPPCO paid or issued to complete this business combination was \$444.7 million, which consisted of \$258.1 million in cash and 4,854,899 newly issued TEPPCO units. Additionally, TEPPCO assumed approximately \$63.2 million of Cenac's debt in the transaction. TEPPCO acquired 42 tow boats, 89 tank barges and the economic benefit of certain related commercial agreements. This business serves refineries and storage terminals along the Mississippi, Illinois and Ohio rivers and the Intracoastal Waterway between Texas and Florida. These assets also gather crude oil from production facilities and platforms along the U.S. Gulf Coast. TEPPCO used a short-term credit facility to finance the cash portion of the acquisition price and to repay the \$63.2 million of debt assumed in this transaction.

Also in February 2008, TEPPCO purchased related marine assets from Horizon Maritime, L.L.C. ("Horizon"), a privately held Houston-based company and an affiliate of Cenac, for \$80.8 million in cash. In this transaction, TEPPCO acquired seven tow boats, 17 tank barges, rights to two tow boats under construction and the economic benefit of certain related commercial agreements. In April 2008, TEPPCO paid an additional \$3.0 million to Horizon pursuant to the purchase agreement upon delivery of one of the tow boats under construction, and in June 2008, TEPPCO paid an additional \$3.8 million upon delivery of the second tow boat. These vessels transport asphalt, heavy fuel oil and other heated oil products to storage facilities and refineries along the Mississippi, Illinois and Ohio Rivers and the Intracoastal Waterway. TEPPCO used a short-term credit facility to finance this acquisition.

The results of operations related to these assets are included in our Statements of Consolidated Operations beginning at the date of acquisition.

<u>Other Transactions</u>. Other business combinations during 2008 primarily consisted of the acquisition of a natural gas gathering system located in the Piceance Basin of northwestern Colorado and additional interests in three consolidated NGL pipeline systems located along the U.S. Gulf Coast and southeastern United States.

2007 Transactions

Our expenditures for business combinations during the year ended December 31, 2007 primarily relate to the acquisition of a business with natural gas pipelines located in southeast Texas.

NOTE 11. INTANGIBLE ASSETS AND GOODWILL

Identifiable Intangible Assets

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

	DE	CEMBER 31, 20	009	DECEMBER 31, 2008				
	GROSS VALUE	ACCUM. AMORT.	CARRYING VALUE	GROSS VALUE	ACCUM. AMORT.	CARRYING VALUE		
NGL Pipelines & Services: (1)								
Customer relationship intangibles	\$ 237.4	\$ (86.5)	\$ 150.9	\$ 237.4	\$ (68.7)	\$ 168.7		
Contract-based intangibles	321.4	(156.7)	164.7	320.3	(137.6)	182.7		
Segment total	558.8	(243.2)	315.6	557.7	(206.3)	351.4		
Onshore Natural Gas Pipelines & Services:								
Customer relationship intangibles (2)	372.0	(124.3)	247.7	372.0	(103.2)	268.8		
Contract-based intangibles	565.3	(285.8)	279.5	565.3	(249.7)	315.6		
Segment total	937.3	(410.1)	527.2	937.3	(352.9)	584.4		
Onshore Crude Oil Pipelines & Services:								
Contract-based intangibles	10.0	(3.5)	6.5	10.0	(3.1)	6.9		
Segment total	10.0	(3.5)	6.5	10.0	(3.1)	6.9		
Offshore Pipelines & Services:								
Customer relationship intangibles	205.8	(105.3)	100.5	205.8	(90.7)	115.1		
Contract-based intangibles	1.2	(0.2)	1.0	1.2	(0.1)	1.1		
Segment total	207.0	(105.5)	101.5	207.0	(90.8)	116.2		
Petrochemical & Refined Products Services: (3)								
Customer relationship intangibles	104.6	(18.8)	85.8	104.9	(13.8)	91.1		
Contract-based intangibles	42.1	(13.9)	28.2	41.1	(8.2)	32.9		
Segment total	146.7	(32.7)	114.0	146.0	(22.0)	124.0		
Total all segments	\$1,859.8	\$ (795.0)	\$ 1,064.8	\$ 1,858.0	\$ (675.1)	\$1,182.9		

⁽¹⁾ In 2008, we acquired \$6.0 million of certain permits related to our Mont Belvieu complex and had \$12.7 million of purchase price allocation adjustments related to San Felipe customer relationships from a 2007 business combination.

The following table presents the amortization expense of our intangible assets by segment for the periods indicated:

	FOR YEAR ENDED DECEMBER 31,						
	2009	2008	2007				
NGL Pipelines & Services	\$ 36.9	\$ 40.7	\$ 38.2				
Onshore Natural Gas Pipelines & Services	57.2	61.7	64.4				
Onshore Crude Oil Pipelines & Services	0.4	0.5	0.5				
Offshore Pipelines & Services	14.7	16.9	19.3				
Petrochemical & Refined Products Services	10.7	10.2	2.8				
Total all segments	\$ 119.9	\$ 130.0	\$ 125.2				

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

2010	2011	2012	2013	2014
\$ 112.2	\$ 105.0	\$ 89.4	\$ 82.4	\$ 78.1

⁽²⁾ In 2008, we acquired \$9.8 million of customer relationships due to the Great Divide business combination.

⁽³⁾ Amount includes a non-cash impairment charge of \$0.6 million in 2009 related to certain intangible assets, see Note 6 for additional information.

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

<u>Customer relationship intangible assets</u>. Customer relationship intangible assets represent the estimated economic value assigned to certain relationships acquired in connection with business combinations and asset purchases whereby (i) we acquired information about or access to customers and now have regular contact with them and (ii) the customers now have the ability to make direct contact with us. Customer relationships may arise from contractual arrangements (such as supplier contracts and service contracts) and through means other than contracts, such as through regular contact by sales or service representatives.

At December 31, 2009, the carrying value of our customer relationship intangible assets was \$584.9 million. The following information summarizes the significant components of this category of intangible assets:

- San Juan Gathering System customer relationships: We acquired these customer relationships in connection with the GulfTerra Merger, which was completed on September 30, 2004. At December 31, 2009, the carrying value of this group of intangible assets was \$220.8 million. These intangible assets are being amortized to earnings over their estimated economic life of 35 years through 2039. Amortization expense is recorded using a method that closely resembles the pattern in which the economic benefits of the underlying natural gas resource bases are expected to be consumed or otherwise used.
- Offshore Pipeline & Platform customer relationships: We acquired these customer relationships in connection with the GulfTerra Merger. At December 31, 2009, the carrying value of this group of intangible assets was \$100.5 million. These intangible assets are being amortized to earnings over their estimated economic lives, which range from 18 to 33 years (i.e., through 2022 to 2037). Amortization expense is recorded using a method that closely resembles the pattern in which the economic benefits of the underlying crude oil and natural gas resource bases are expected to be consumed or otherwise used.
- Encinal natural gas processing customer relationship: We acquired this customer relationship in connection with our Encinal acquisition in 2006. At December 31, 2009, the carrying value of this intangible asset was \$89.3 million. This intangible asset is being amortized to earnings over its estimated economic life of 20 years through 2026. Amortization expense is recorded using a method that closely resembles the pattern in which the economic benefit of the underlying natural gas resource bases are expected to be consumed or otherwise used.

<u>Contract-based intangible assets</u>. Contract-based intangible assets represent specific commercial rights we acquired in connection with business combinations or asset purchases. At December 31, 2009, the carrying value of our contract-based intangible assets was \$479.9 million. The following information summarizes the significant components of this category of intangible assets:

- Jonah Gas Gathering Company ("Jonah") natural gas gathering agreements: These intangible assets represent the value attributed to certain of Jonah's natural gas gathering contracts that were originally acquired by TEPPCO in 2001. At December 31, 2009, the carrying value of this group of intangible assets was \$125.0 million. These intangible assets are being amortized to earnings using a units-of-production method based on throughput volumes on the Jonah system, which is estimated to extend through 2041.
- Val Verde natural gas gathering agreements: These intangible assets represent the value attributed to certain natural gas gathering agreements associated with our Val Verde Gathering System that was originally acquired by TEPPCO in 2002. At December 31, 2009, the carrying value of these intangible assets was \$98.4 million. These intangible assets are being amortized to earnings using a units-of-production method based on throughput volumes on the Val Verde Gathering System, which is estimated to extend through 2032.

- Shell Processing Agreement: This margin-band/keepwhole processing agreement grants us the right to process Shell Oil Company's (or its assignee's) current and future natural gas production within the state and federal waters of the Gulf of Mexico. We acquired the Shell Processing Agreement in connection with our 1999 purchase of certain of Shell's midstream energy assets located along the U.S. Gulf Coast. At December 31, 2009, the carrying value of this intangible asset was \$105.9 million. This intangible asset is being amortized to earnings on a straight-line basis over its estimated economic life of 20 years through 2019.
- Mississippi natural gas storage contracts: These intangible assets represent the value assigned by us to certain natural gas storage contracts associated with our Petal and Hattiesburg, Mississippi storage facilities. These facilities were acquired in connection with the GulfTerra Merger. At December 31, 2009, the carrying value of these intangible assets was \$55.4 million. These intangible assets are being amortized to earnings on a straight-line basis over the remainder of their respective contract terms, which range from eight to 18 years (i.e., 2012 through 2022).

Goodwill

Goodwill represents the excess of the purchase price of an acquired business over the amounts assigned to assets acquired and liabilities assumed in the transaction. Goodwill is not amortized; however, it is subject to annual impairment testing at the beginning of each fiscal year. The following table presents the changes in the carrying amount of goodwill for the periods presented:

	NGL PELINES SERVICES	NAT!	ISHORE URAL GAS PELINES ERVICES	C	NSHORE RUDE OIL IPELINES SERVICES	P	FFSHORE IPELINES SERVICES	& Pl	OCHEMICAL REFINED RODUCTS ERVICES	COI	NSOLIDATED Totals
Balance at January 1, 2007	\$ 224.8	\$	284.9	\$	303.0	\$	82.1	\$	917.3	\$	1,812.1
Goodwill related to acquisitions	1.2		_		_		_		_		1.2
Balance at December 31, 2007	226.0		284.9		303.0		82.1		917.3		1,813.3
Goodwill related to acquisitions	115.2		_		_		_		91.1		206.3
Balance at December 31, 2008	341.2		284.9		303.0		82.1		1,008.4		2,019.6
Impairment charges (1)	_		_		_		_		(1.3)		(1.3)
Balance at December 31, 2009 (2)	\$ 341.2	\$	284.9	\$	303.0	\$	82.1	\$	1,007.1	\$	2,018.3

⁽¹⁾ See Note 6 for additional information regarding impairment charges recorded during year ended December 31, 2009.

Our goodwill impairment testing involves the determination of a reporting unit's fair value, which is predicated based on our assumptions regarding the future economic prospects of the reporting unit. Such assumptions include: (i) discrete financial forecasts for the assets contained within the reporting unit, which rely on management's estimates of operating margins and transportation volumes; (ii) long-term growth rates for cash flows beyond the discrete forecast period; and (iii) appropriate discount rates. Based on our most recent goodwill impairment testing, each reporting unit's fair value was substantially in excess (a minimum of 10%) of its carrying value.

⁽²⁾ The total carrying amount of goodwill at December 31, 2009 is reflected net of \$1.3 million of accumulated impairment charges.

The following table summarizes components of our goodwill amounts by segment at the dates indicated:

	DECEMBER 31,			
	2	009	2	800
NGL Pipelines & Services:				
Acquisition of ownership interests in TEPPCO	\$	72.2	\$	72.2
GulfTerra Merger		23.8		23.8
Acquisition of Encinal		95.3		95.3
Acquisition of interest in Dixie		80.3		80.3
Acquisition of Great Divide		44.9		44.9
Acquisition of Indian Springs natural gas processing business		13.2		13.2
Other		11.5		11.5
Onshore Natural Gas Pipelines & Services:				
GulfTerra Merger		279.9		279.9
Other		5.0		5.0
Onshore Crude Oil Pipeline & Services:				
Acquisition of ownership interests in TEPPCO		288.8		288.8
Acquisition of crude oil pipeline and services business		14.2		14.2
Offshore Pipelines & Services:				
GulfTerra Merger		82.1		82.1
Petrochemical & Refined Products Services:				
Acquisition of ownership interests in TEPPCO		842.3		842.3
Acquisition of marine services businesses		90.4		90.4
Acquisition of Mont Belvieu propylene fractionation business		73.7		73.7
Other (1)		0.7		2.0
Total	\$ 2	2,018.3	\$ 2	2,019.6

⁽¹⁾ Includes a non-cash impairment charge of \$1.3 million, see Note 6 for additional information.

Goodwill attributable to the acquisition of ownership interests in TEPPCO. As a result of our ownership of 100% of the limited and general partner interests of TEPPCO following the recently completed TEPPCO Merger, we applied push down accounting to the \$1.2 billion of goodwill recorded by affiliates of EPCO (which are under common control with us) when they acquired 100% of the membership interests of TEPPCO GP and 4,400,000 TEPPCO limited partner units from a third-party in February 2005. The \$1.2 billion in push down goodwill represents the excess of the purchase price paid by such affiliates to acquire ownership interests in TEPPCO in February 2005 over the respective fair value of assets acquired and liabilities assumed in the February 2005 transaction. Management attributes the \$1.2 billion of goodwill to the future economic benefits we may realize from our ownership of TEPPCO, including anticipated commercial synergies and cost savings.

TEPPCO owns and operates an extensive network of assets that facilitate the movement, marketing, gathering and storage services of various commodities and energy-related products. TEPPCO's pipeline network is comprised of approximately 12,500 miles of pipelines that gather and transport refined products, crude oil, natural gas and NGLs, including one of the largest common carrier pipelines for refined products in the United States. TEPPCO also owns a marine services business that transports refined products, crude oil, asphalt, condensate, heavy fuel oil and other heated oil products via tow boats and tank barges. In addition, TEPPCO owns interests in the Seaway and Centennial pipeline systems.

<u>Goodwill attributable to GulfTerra Merger</u>. Goodwill recorded in connection with the GulfTerra Merger can be attributed to our belief (at the time the merger was consummated) that the combined partnerships would benefit from the strategic location of each partnership's assets and the industry relationships that each possessed. In addition, we 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. Based on miles of pipelines, GulfTerra was one of the largest natural gas gathering and transportation companies in the United States, serving producers in the central and western Gulf of Mexico and onshore in Texas and New Mexico. These regions offer us significant growth potential through the acquisition and construction of additional pipelines, platforms, processing and storage facilities and other midstream energy infrastructure.

Acquisition of Encinal. Management attributes goodwill recorded in connection with the Encinal acquisition to potential future benefits we may realize from our other south Texas processing and NGL businesses as a result of acquiring the Encinal business. Specifically, our acquisition of the long-term dedication rights associated with the Encinal business is expected to add value to our south Texas processing facilities and related NGL businesses due to increased volumes. The Encinal goodwill is recorded as part of the NGL Pipelines & Services business segment due to management's belief that such future benefits will accrue to businesses classified within this segment.

Acquisition of Dixie and Great Divide. In 2008, we recorded goodwill in connection with our acquisition of the remaining third-party interest in Dixie and with the acquisition of Great Divide. The remaining ownership interests in Dixie were acquired from Amoco Pipeline Holding Company in August 2008. Management attributes the goodwill to future earnings growth on the Dixie Pipeline. Specifically, a 100% ownership interest in the Dixie Pipeline will increase our flexibility to pursue future opportunities. Great Divide was acquired from EnCana in December 2008. The Great Divide goodwill is attributable to management's expectations of future economics benefits derived from incremental natural gas processing margins and other downstream activities.

The Dixie and Great Divide goodwill amounts are recorded as part of the NGL Pipelines & Services business segment due to management's belief that such future benefits will accrue to businesses classified within this segment.

<u>Acquisition of Cenac and Horizon</u>. Also in 2008, we recorded goodwill in connection with our acquisition of marine services businesses, which are recorded as a part of the Petrochemical & Refined Products Services business segment due to management's belief of potential future economic benefits we expect to realize as a result of acquiring these assets.

<u>Other goodwill amounts</u>. The remainder of our goodwill amounts are associated with prior acquisitions, principally that of our crude oil pipeline and services business originally purchased by TEPPCO in 2001, our purchase of a propylene fractionation business in February 2002 and our acquisition of indirect ownership interests in the Indian Springs natural gas gathering and processing business in January 2005.

NOTE 12. DEBT OBLIGATIONS

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

	DECEMBER 31,		
	2009		2008
EPO senior debt obligations:			
Multi-Year Revolving Credit Facility, variable-rate, due November 2012	\$ 195.		800.0
Pascagoula MBFC Loan, 8.70% fixed-rate, due March 2010 (1)	54.		54.0
Petal GO Zone Bonds, variable-rate, due August 2037	57.	5	57.5
Yen Term Loan, 4.93% fixed-rate, due March 2009	=	_	217.6
Senior Notes B, 7.50% fixed-rate, due February 2011	450.		450.0
Senior Notes C, 6.375% fixed-rate, due February 2013	350.		350.0
Senior Notes D, 6.875% fixed-rate, due March 2033	500.	0	500.0
Senior Notes F, 4.625% fixed-rate, due October 2009	-	_	500.0
Senior Notes G, 5.60% fixed-rate, due October 2014	650.	0	650.0
Senior Notes H, 6.65% fixed-rate, due October 2034	350.	0	350.0
Senior Notes I, 5.00% fixed-rate, due March 2015	250.	0	250.0
Senior Notes J, 5.75% fixed-rate, due March 2035	250.	0	250.0
Senior Notes K, 4.95% fixed-rate, due June 2010 (1)	500.	0	500.0
Senior Notes L, 6.30% fixed-rate, due September 2017	800.	0	800.0
Senior Notes M, 5.65% fixed-rate, due April 2013	400.	0	400.0
Senior Notes N, 6.50% fixed-rate, due January 2019	700.	0	700.0
Senior Notes O, 9.75% fixed-rate, due January 2014	500.	0	500.0
Senior Notes P, 4.60% fixed-rate, due August 2012	500.	0	_
Senior Notes Q, 5.25% fixed-rate, due January 2020	500.	0	_
Senior Notes R, 6.125% fixed-rate, due October 2039	600.	0	_
Senior Notes S, 7.625% fixed-rate, due February 2012 (2)	490.	5	_
Senior Notes T, 6.125% fixed-rate, due February 2013 (2)	182.	5	_
Senior Notes U, 5.90% fixed-rate, due April 2013 (2)	237.	6	_
Senior Notes V, 6.65% fixed-rate, due April 2018 (2)	349.	7	_
Senior Notes W, 7.55% fixed-rate, due April 2038 (2)	399.	6	_
TEPPCO senior debt obligations:			
TEPPCO Revolving Credit Facility, variable-rate, due December 2012	-	_	516.7
TEPPCO Senior Notes (2)	40.	1	1,700.0
Duncan Energy Partners' debt obligations:			
DEP Revolving Credit Facility, variable-rate, due February 2011	175.	0	202.0
DEP Term Loan, variable-rate, due December 2011	282.	3	282.3
Total principal amount of senior debt obligations	9,764.	3	10,030.1
EPO Junior Subordinated Notes A, fixed/variable-rate, due August 2066	550.		550.0
EPO Junior Subordinated Notes B, fixed/variable-rate, due January 2068	682.	7	682.7
EPO Junior Subordinated Notes C, fixed/variable-rate, due June 2067 (2)	285.	8	_
TEPPCO Junior Subordinated Notes, fixed/variable-rate, due June 2067 (2)	14.		300.0
Total principal amount of senior and junior debt obligations	11,297.		11,562.8
Other, non-principal amounts:			
Change in fair value of debt-related derivative instruments (see Note 6)	44.	4	51.9
Unamortized discounts, net of premiums	(18.		(12.6)
Unamortized deferred net gains related to terminated interest rate swaps (see Note 6)	23.		35.8
Total other, non-principal amounts	49.		75.1
Total long-term debt	\$ 11,346.		11,637.9
			, -

⁽¹⁾ Long-term and current maturities of debt reflect the classification of such obligations at December 31, 2009 after taking into consideration EPO's ability to use available borrowing capacity under its Multi-Year Revolving Credit Facility.

⁽²⁾ Substantially all of TEPPCO debt obligations were exchanged for a corresponding series of new EPO notes in October 2009 in connection with the TEPPCO Merger.

Letters of Credit

At December 31, 2009, EPO had outstanding a \$50.0 million letter of credit related to its commodity derivative instruments and a \$58.3 million letter of credit related to its Petal GO Zone Bonds. These letter of credit facilities do not reduce the amount available for borrowing under EPO's credit facilities.

Parent-Subsidiary Guarantor Relationships

Enterprise Products Partners acts as guarantor of the consolidated debt obligations of EPO with the exception of the DEP Revolving Credit Facility and the DEP Term Loan Agreement. If EPO were to default on any of its guaranteed debt, Enterprise Products Partners L.P. would be responsible for full repayment of that obligation. Additionally, TEPPCO's remaining debt obligations are non-recourse to Enterprise Products Partners.

EPO's Debt Obligations

Multi-Year Revolving Credit Facility. We have in place a \$1.75 billion unsecured revolving credit facility, including the issuance of letters of credit ("Multi-Year Revolving Credit Facility"), which matures in November 2012. Our credit facility has a term-out option that allows for us on the maturity date to convert the principal balance of all revolving loans then outstanding into a non-revolving one-year term loan. The credit facility allows us to request unlimited one-year extensions of the maturity date, subject to lender approval. The total amount of the bank commitments may be increased, without the consent of the lenders, by an amount not exceeding \$500.0 million by adding one or more lenders to the facility and/or requesting that the commitments of existing lenders be increased.

As defined by the credit agreement, variable interest rates charged under this facility bear interest at a Eurodollar rate plus an applicable margin. In addition, EPO is required to pay a quarterly facility fee on each lender's commitment irrespective of commitment usage. The applicable margins will be increased by 0.1% per annum for each day that the total outstanding loans and letter of credit obligations under the facility exceeds 50% of the total lender commitments. Also, if we exercise our term-out option at the maturity date, the applicable margin will increase by 0.125% per annum and, if immediately prior to such election, the total amount of outstanding loans and letter of credit obligations under the facility exceeds 50% of the total lender commitments, the applicable margin with respect to the term loan will increase by an additional 0.1% per annum.

The Multi-Year Revolving Credit Facility contains certain financial and other customary affirmative and negative covenants. The credit agreement also restricts EPO's ability to pay cash distributions to us if a default or an event of default (as defined in the credit agreement) has occurred and is continuing at the time such distribution is scheduled to be paid.

EPO's borrowings under this agreement are unsecured general obligations that are non-recourse to EPGP. We have guaranteed repayment of amounts due under this revolving credit agreement through an unsecured guarantee.

<u>Pascagoula MBFC Loan</u>. This loan, from the Mississippi Business Finance Corporation ("MBFC"), matured on March 1, 2010 and was repaid.

<u>Petal GO Zone Bonds</u>. In August 2007, Petal Gas Storage, L.L.C. ("Petal"), a wholly owned subsidiary of EPO, borrowed \$57.5 million from the MBFC pursuant to a loan agreement and promissory note between Petal and the MBFC. The promissory note between Petal and MBFC is guaranteed by EPO and supported by a letter of credit issued by a bank that expires in August 2014. On the same date, the MBFC issued \$57.5 million in Gulf Opportunity Zone Tax-Exempt ("GO Zone") bonds to various third parties. The promissory note and the GO Zone bonds have identical terms including floating interest rates and maturities of 30 years.

<u>Petal MBFC Loan</u>. In August 2007, Petal entered into a loan agreement and a promissory note with the MBFC under which Petal may borrow up to \$29.5 million. On the same date, the MBFC issued taxable bonds to EPO in the maximum amount of \$29.5 million. At December 31, 2009, there was \$8.9 million outstanding under the loan and the bonds. The promissory note and the taxable bonds have identical terms. The loan and bonds and the related interest expense and income amounts are netted in preparing our consolidated financial statements.

<u>Japanese Yen Term Loan</u>. In November 2008, EPO executed the Yen Term Loan in the amount of approximately 20.7 billion yen (approximately \$217.6 million U.S. Dollar equivalent on the closing date). EPO entered into foreign exchange currency swaps that effectively converted the loan into a U.S. Dollar loan with a fixed interest rate of approximately 4.93%. The Yen Term Loan matured on March 30, 2009. Additionally, EPO executed a forward purchase exchange (yen principal and interest due) at an exchange rate of 94.515 to eliminate foreign exchange risk, resulting in a payment of US\$221.6 million on March 30, 2009.

<u>364-Day Revolving Credit Facility</u>. From November 2008 through June 2009, we had a \$375.0 million standby credit facility. The facility was never utilized and was terminated in June 2009 under its terms as a result of issuing senior notes.

<u>Senior Notes</u>. Our senior fixed-rate notes are unsecured obligations of EPO and rank equally with its existing and future unsecured and unsubordinated indebtedness. They are senior to any future subordinated indebtedness. EPO's borrowings under these notes are non-recourse to EPGP. We have guaranteed repayment of amounts due under these notes through an unsecured and unsubordinated guarantee. Our guarantee of such notes is non-recourse to EPGP. Our senior notes are subject to make-whole redemption rights and were issued under indentures containing certain covenants, which generally restrict EPO's ability, with certain exceptions, to incur debt secured by liens and engage in sale and leaseback transactions.

In June 2009, EPO issued \$500.0 million in principal amount of 3-year senior unsecured notes (Senior Notes P) at 99.95% of their principal amount. In October 2009, EPO issued: (i) \$500.0 million in principal amount of 10-year unsecured notes (Senior Notes Q) at 99.355% of their principal amount and (ii) \$600.0 million in principal amount of 30-year unsecured notes (Senior Notes R) at 99.386% of their principal amount. Net proceeds from the issuance of these senior notes were used to (i) repay amounts borrowed under a \$200.0 million term loan that EPO entered into during April 2009; (ii) repay \$500.0 million in aggregate principal amount of Senior Notes F that matured in October 2009; (iii) temporarily reduce borrowings outstanding under EPO's Multi-Year Revolving Credit Facility; and (iv) for general partnership purposes.

In connection with the TEPPCO Merger, EPO offered to exchange all of TEPPCO's outstanding senior notes for a corresponding series of new EPO senior notes. The exchanges were completed on October 27, 2009 as follows:

TEPPCO NOTES EXCHANGED	CORRESPONDING SERIES OF NEW EPO NOTES	AGGREGATE PRINCIPAL AMOUNT	RINCIPAL AMOUNT AMOU	
TEPPCO Senior Notes, 7.625% fixed-rate, due February 2012	Senior Notes S, 7.625% fixed-rate, due February 2012	\$ 500.0	\$ 490.5	\$ 9.5
TEPPCO Senior Notes, 6.125% fixed-rate, due February 2013 TEPPCO Senior Notes, 5.90%	Senior Notes T, 6.125% fixed-rate, due February 2013 Senior Notes U, 5.90%	200.0	182.5	17.5
fixed-rate, due April 2013 TEPPCO Senior Notes, 6.65%	fixed-rate, due April 2013 Senior Notes V, 6.65%	250.0	237.6	12.4
fixed-rate, due April 2018 TEPPCO Senior Notes, 7.55%	fixed-rate, due April 2018 Senior Notes W, 7.55%	350.0	349.7	0.3
fixed-rate, due April 2038	fixed-rate, due April 2038	<u>400.0</u> \$ 1,700.0	399.6 \$ 1,659.9	\$ 40.1

<u>Junior Subordinated Notes</u>. EPO's payment obligations under its junior notes are subordinated to all of its current and future senior indebtedness (as defined in the related indenture agreement). We have guaranteed repayment of amounts due under these notes through an unsecured and subordinated guarantee. The indenture agreement governing these notes allows EPO to defer interest payments on one or more occasions for up to ten consecutive years subject to certain conditions. During any period in which interest payments are deferred and subject to certain exceptions, neither we nor EPO can declare or make any distributions to any of our respective equity securities or make any payments on indebtedness or other obligations that rank pari passu with or are subordinate to our junior notes. Each series of our subordinated junior notes are ranked equally with each other. Generally, each series of junior subordinated notes are not redeemable by EPO without payment of a make-whole premium while the notes bear interest at a fixed annual rate.

In connection with the issuance of each series of junior subordinated notes, EPO entered into separate Replacement Capital Covenants in favor of covered debt holders (as defined in the underlying documents) pursuant to which EPO agreed for the benefit of such debt holders that it would not redeem or repurchase such junior notes unless such redemption or repurchase is made using proceeds from the issuance of certain securities.

In connection with the TEPPCO Merger, EPO offered to exchange TEPPCO's outstanding junior subordinated notes for a corresponding series of new EPO junior subordinated notes. The exchange was completed on October 27, 2009:

TEPPCO NOTES EXCHANGED	CORRESPONDING SERIES OF NEW EPO NOTES	PI	GREGATE RINCIPAL MOUNT	A	RINCIPAL Mount Changed	A	INCIPAL Mount Maining
TEPPCO Junior Subordinated Notes,	EPO Junior Subordinated Notes C,						
fixed/variable-rate, due June 2067	fixed/variable-rate, due June 2067	\$	300.0	\$	285.8	\$	14.2

The following table summarizes the interest rate terms of our junior subordinated notes:

SERIES	FIXED ANNUAL INTEREST RATE	VARIABLE ANNUAL INTEREST RATE THEREAFTER
Junior Subordinated Notes A	8.375% through August 2016 (1)	3-month LIBOR rate + 3.708% (4)
		Greater of: (i) 3-month LIBOR rate + 2.68% or (ii)
Junior Subordinated Notes B	7.034% through January 2018 (2)	7.034% (5)
Junior Subordinated Notes C	7.00% through June 2017 (3)	3-month LIBOR rate + 2.778% (6)

- (1) Interest is payable semi-annually in arrears in February and August of each year, which commenced in February 2007.
- (2) Interest is payable semi-annually in arrears in January and July of each year, which commenced in January 2008.
- (3) Interest is payable semi-annually in arrears in June and December of each year, which commenced in December 2009.
- (4) Interest is payable quarterly in arrears in February, May, August and November of each year commencing in November 2016
- (5) Interest is payable quarterly in arrears in January, April, July and October of each year commencing in April 2018.
- (6) Interest is payable quarterly in arrears in March, June, September and December of each year commencing in June 2017.

TEPPCO's Debt Obligations

<u>TEPPCO Revolving Credit Facility</u>. Upon consummation of the TEPPCO Merger, EPO repaid and terminated all of the outstanding indebtedness under the TEPPCO Revolving Credit Facility.

<u>TEPPCO Senior Notes</u>. As previously discussed, on October 27, 2009, \$1.66 billion of the TEPPCO Senior Notes were exchanged for an equal amount of new EPO Senior Notes. In addition to the debt exchange, substantially all of the restrictive covenants and reporting requirements associated with the remaining TEPPCO Senior Notes were eliminated through amendments that became effective on October 26, 2009.

TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gas Gathering Company, L.P. (collectively, the "Subsidiary Guarantors") acted as guarantors of TEPPCO's outstanding senior notes through November 2009. The subsidiary guarantees were terminated in November 2009.

<u>TEPPCO Junior Subordinated Notes</u>. As discussed above, on October 27, 2009, \$285.8 million of the TEPPCO Junior Subordinated Notes were exchanged for an equal amount of new EPO Junior Subordinated Notes. In addition to the debt exchange, substantially all of the restrictive covenants and reporting requirements associated with the remaining TEPPCO Junior Subordinated Notes were eliminated through amendments that became effective on October 26, 2009.

The Subsidiary Guarantors also acted as guarantors, on a junior subordinated basis, of TEPPCO's outstanding junior subordinated notes through November 2009. These subsidiary guarantees were terminated in November 2009.

The terms and provisions of the TEPPCO's Junior Subordinated Notes are similar to each series of EPO's junior subordinated notes. For example, they: (i) are general unsecured subordinated obligations; (ii) allow interest payments to be deferred for multiple periods of up to ten consecutive years; and (iii) are subordinated in right of payment to all existing and future senior indebtedness. The maturity date, the interest rate and the interest payment due dates are the identical to EPO's Junior Subordinated Notes C as discussed above.

In connection with the issuance of the TEPPCO Junior Subordinated Notes, TEPPCO and its Subsidiary Guarantors entered into a Replacement Capital Covenant in favor of the covered debt holders (as defined in the underlying documents) pursuant to which TEPPCO agreed for the benefit of such debt holders that it would not redeem or repurchase such junior notes unless such redemption or repurchase is made using proceeds from the issuance of certain securities. The Replacement Capital Covenant is not a term of the governing indenture or the junior subordinated notes.

Duncan Energy Partners' Debt Obligations

We consolidate the debt of Duncan Energy Partners with that of our own; however, we do not have the obligation to make interest payments or debt payments with respect to the debt of Duncan Energy Partners.

<u>DEP Revolving Credit Facility</u>. Duncan Energy Partners has in place a \$300 million unsecured revolving credit facility, all of which may be used for letters of credit, with a \$30.0 million sublimit for Swingline loans. This credit facility will be used by Duncan Energy Partners in the future to fund working capital and other capital requirements and for general partnership purposes. Duncan Energy Partners may make up to two requests for one-year extensions of the maturity date, which is February 2011 (subject to certain restrictions). The revolving credit facility is available to pay distributions to its partners, fund working capital, make acquisitions and provide payment for general purposes. Duncan Energy Partners can increase the revolving credit facility, without consent of the lenders, by an amount not to exceed \$150.0 million, by adding to the facility one or more new lenders and/or requesting that the commitments of existing lenders be increased.

This revolving credit facility offers the following unsecured loans, each having different interest requirements: (i) a Eurodollar rate, plus the applicable Eurodollar margin (as defined in the credit agreement); (ii) Base Rate loans bear interest at a rate per annum equal to the higher of (a) the rate of interest publicly announced by the administrative agent, Wachovia Bank, National Association, as its Base Rate and (b) 0.5% per annum above the Federal Funds Rate in effect on such date; and (iii) Swingline loans bear interest at a rate per annum equal to LIBOR plus an applicable LIBOR margin.

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

<u>DEP Term Loan</u>. In April 2008, Duncan Energy Partners entered into a standby term loan agreement consisting of commitments for up to a \$300.0 million senior unsecured term loan. Subsequently, commitments under this agreement decreased to \$282.3 million due to bankruptcy of one of the lenders. Duncan Energy Partners borrowed the full amount of \$282.3 million on December 8, 2008 in connection with the acquisition of equity interests in midstream energy businesses.

Duncan Energy Partners may prepay loans under the term loan agreement at any time, subject to prior notice in accordance with the credit agreement. Loans may also be payable earlier in connection with an event of default.

Loans under the term loan agreement bear interest of the type specified in the applicable borrowing request, and consist of either Alternate Base Rate loans or Eurodollar loans. The term loan agreement contains certain financial and other customary affirmative and negative covenants.

Dixie Revolving Credit Facility

Dixie's debt obligation consisted of a senior, unsecured revolving credit facility having a borrowing capacity of \$28.0 million. This credit facility was terminated in January 2009.

Canadian Debt Obligation

In May 2007, Canadian Enterprise Gas Products, Ltd., a wholly owned subsidiary of EPO, entered into a \$30.0 million Canadian revolving credit facility with The Bank of Nova Scotia. The credit facility, which includes the issuance of letters of credit, matures in October 2011. Letters of credit outstanding under this facility reduce the amount available for borrowings. The credit facility contains customary covenants and events of default. The obligations under the credit facility are guaranteed by EPO. As of December 31, 2009, there were no debt obligations outstanding under this credit facility.

Covenants

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

Information Regarding Variable Interest Rates Paid

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

	RANGE OF INTEREST RATES PAID	WEIGHTED-AVERAGE INTEREST RATE PAID
EPO Multi-Year Revolving Credit Facility	0.73% to 3.25%	0.95%
TEPPCO Revolving Credit Facility	0.75% to 3.25%	0.88%
DEP Revolving Credit Facility	0.81% to 2.74%	1.48%
DEP Term Loan	0.93% to 2.93%	1.15%
Petal GO Zone Bonds	0.21% to 2.75%	0.60%

Consolidated Debt Maturity Table

The following table presents contractually scheduled maturities of our consolidated debt obligations for the next five years, and in total thereafter:

		SCHEDULED MATURITIES OF DEBT					
	TOTAL	2010 (1)	2011	2012	2013	2014	AFTER 2014
Revolving Credit Facilities	\$ 370.5	\$ - \$	175.0	\$ 195.5	\$ —	\$ —	\$ —
Senior Notes	9,000.0	500.0	450.0	1,000.0	1,200.0	1,150.0	4,700.0
Term Loans	282.3	_	282.3	_			_
Junior Subordinated Notes	1,532.7	_	_	_	_	_	1,532.7
Other	111.5	54.0	_	_	_	_	57.5
Total	\$11,297.0	\$ 554.0 \$	907.3	\$ 1,195.5	\$ 1,200.0	\$ 1,150.0	\$ 6,290.2

⁽¹⁾ Long-term and current maturities of debt reflect the classification of such obligations on our Consolidated Balance Sheet at December 31, 2009 after taking into consideration EPO's ability to use available borrowing capacity under its Multi-Year Revolving Credit Facility.

Debt Obligations of Unconsolidated Affiliates

We have three unconsolidated affiliates with long-term debt obligations. The following table shows: (i) the ownership interest in each entity at December 31, 2009; (ii) total debt of each unconsolidated affiliate at December 31, 2009 (on a 100% basis to the unconsolidated affiliate); and (iii) the corresponding scheduled maturities of such debt:

		SCHEDULED MATURITIES OF DEBT						
	OWNERSHIP INTEREST	TOTAL	2010	2011	2012	2013	2014	AFTER 2014
Poseidon	36%	\$ 92.0	\$ —	\$ 92.0	\$ —	\$ —	\$ —	\$ —
Evangeline	49.5%	10.7	3.2	7.5	_	_	_	_
Centennial	50%	120.0	9.1	9.0	8.9	8.6	8.6	75.8
Total		\$ 222.7	\$ 12.3	\$108.5	\$ 8.9	\$ 8.6	\$ 8.6	\$ 75.8

The credit agreements of these unconsolidated affiliates include customary covenants, including financial covenants. These businesses were in compliance with such financial covenants at December 31, 2009. The credit agreements of these unconsolidated affiliates restrict their ability to pay cash dividends or distributions if a default or an event of default (as defined in each credit agreement) has occurred and is continuing at the time such dividend or distribution is scheduled to be paid.

The following information summarizes the significant terms of the debt obligations of these unconsolidated affiliates at December 31, 2009:

<u>Poseidon</u>. At December 31, 2009, Poseidon's debt obligations consisted of \$92.0 million outstanding under its \$150.0 million variable-rate revolving credit facility. Amounts borrowed under this facility mature in May 2011 and are secured by substantially all of Poseidon's assets. The weighted-average variable interest rates charged on this debt at December 31, 2009 and 2008 were 1.88% and 4.31%, respectively.

<u>Evangeline</u>. At December 31, 2009, Evangeline's debt obligations consisted of: (i) \$3.2 million in principal amount of 9.90% fixed-rate Series B senior secured notes due December 2010 and (ii) a \$7.5 million subordinated note payable due in 2011. The Series B senior secured notes are collateralized by Evangeline's property, plant and equipment, proceeds from a gas sales contract and by a debt service reserve requirement.

Evangeline incurred the subordinated note payable as a result of its acquisition of a contract-based intangible asset in the early 1990s. This note is subject to a subordination agreement which prevents the repayment of principal and accrued interest on the subordinated note until such time as the Series B noteholders are either fully cash secured through debt service accounts or have been completely repaid.

Variable-rate interest accrues on the subordinated note at LIBOR plus 0.5%. The weighted-average variable interest rates charged on this note at December 31, 2009 and 2008 were 1.59% and 3.62%, respectively. Accrued interest payable related to the subordinated note was \$10.2 million and \$9.8 million at December 31, 2009 and 2008, respectively.

<u>Centennial</u>. At December 31, 2009, Centennial's debt obligations consisted of \$120.0 million borrowed under a master shelf loan agreement through two private placements, with interest rates ranging from 7.99% to 8.09%. Borrowings under the master shelf agreement mature in May 2024 and are collateralized by substantially all of Centennial's assets and severally guaranteed by Centennial's owners.

We and our joint venture partner in Centennial have each guaranteed one-half of Centennial's debt obligations. If Centennial were to default on its debt obligations, the estimated payment obligation would be \$60.0 million based on amounts outstanding at December 31, 2009. We recognized a liability of \$8.4 million for our share of the Centennial debt guaranty at December 31, 2009.

NOTE 13. EQUITY AND DISTRIBUTIONS

Our common units represent limited partner interests, which give the holders thereof the right to participate in distributions and to exercise the other rights or privileges available to them under our Fifth Amended and Restated Agreement of Limited Partnership (together with all amendments thereto, the "Partnership Agreement"). We are managed by our general partner, EPGP.

In accordance with the Partnership Agreement, capital accounts are maintained for our general partner and 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 consolidated financial statements.

Our Partnership Agreement sets forth the calculation to be used in determining the amount and priority of cash distributions that our limited partners and general partner will receive. The Partnership Agreement also contains provisions for the allocation of net earnings and losses to our limited partners and general partner. For purposes of maintaining partner capital accounts, the Partnership Agreement specifies that items of income and loss shall be allocated among the partners in accordance with their respective percentage interests. Normal income and loss allocations according to percentage interests are done only after giving effect to priority earnings allocations in an amount equal to incentive cash distributions allocated to our general partner.

In August 2005, we revised our Partnership Agreement to allow EPGP, at its discretion, to elect not to make its proportionate capital contributions to us in connection with our issuance of limited partner interests, in which case its 2% general partner interest would be proportionately reduced. At the time of such offerings, EPGP has historically contributed cash to us to maintain its 2% general partner interest. EPGP made such cash contributions to us during the years ended December 31, 2009 and 2008. If EPGP exercises this option in the future, the amount of earnings we allocate to it and the cash distributions it receives from us will be reduced accordingly. If this occurs, EPGP can, under certain conditions, restore its full 2% general partner interest by making additional cash contributions to us.

Registration Statements and Equity Offerings

In general, the Partnership Agreement authorizes us to issue an unlimited number of additional limited partner interests and other equity securities for such consideration and on such terms and conditions as may be established by EPGP in its sole discretion (subject, under certain circumstances, to the approval of our unitholders).

We have filed registration statements with the SEC authorizing the issuance of up to an aggregate 40,000,000 common units in connection with our distribution reinvestment plan ("DRIP"). The DRIP provides unitholders of record and beneficial owners of our common units a voluntary means by which they can increase the number of common units they own by reinvesting the quarterly cash distributions they would otherwise receive into the purchase of additional common units. A total of 33,380,130 common units have been issued under the DRIP registration statement through December 31, 2009.

In May 2004, we filed a registration statement with the SEC authorizing the issuance of up to 1,200,000 common units in connection with our employee unit purchase plan ("EUPP"). Under this plan, employees of EPCO can purchase our common units at a 10% discount through payroll deductions. A total of 832,134 common units have been issued to employees under this plan through December 31, 2009.

In August 2007, we filed a universal shelf registration statement with the SEC that allows us to issue an unlimited amount of debt and equity securities. We have issued 18,927,500 common units in underwritten offerings under this registration statement generating \$452.0 million of net cash proceeds through December 31, 2009. In addition, we have issued \$4.0 billion of senior notes under this registration statement through December 31, 2009.

On September 4, 2009, we agreed to issue 5,940,594 common units in a private placement to EPCO Holdings, Inc., a privately held affiliate controlled by Dan L. Duncan, for \$150.0 million. In accordance with the terms of the private placement, as approved by the ACG Committee of EPGP's Board of Directors on September 1, 2009, the per unit purchase price of \$25.25 was calculated based on a 5% discount to the five-day volume weighted-average price of our common units, as reported by the NYSE at the close of business on September 4, 2009. The common units were issued September 8, 2009.

The following table reflects the number of common units issued and the net cash proceeds received from underwritten and other common unit offerings completed during the periods presented:

	NET CASH PROCEEDS FROM SALE OF COMMON UNITS				
	NUMBER OF COMMON UNITS ISSUED	CONTRIBUTED BY LIMITED PARTNERS	CONTRIBUTED By General Partner	TOTAL NET CASH PROCEEDS	
Fiscal 2007:					
DRIP and EUPP	2,056,615	\$ 60.4	\$ 1.2	\$ 61.6	
Total 2007	2,056,615	\$ 60.4	\$ 1.2	\$ 61.6	
Fiscal 2008:					
DRIP and EUPP	5,523,946	\$ 139.3	\$ 2.8	\$ 142.1	
Total 2008	5,523,946	\$ 139.3	\$ 2.8	\$ 142.1	
Fiscal 2009:					
January underwritten offering	10,590,000	\$ 225.6	\$ 4.6	\$ 230.2	
DRIP and EUPP	12,089,920	290.8	5.9	296.7	
September private placement	5,940,594	150.0	3.1	153.1	
September underwritten offering	8,337,500	226.4	4.6	231.0	
Total 2009	36,958,014	\$ 892.8	\$ 18.2	\$ 911.0	

Net cash proceeds received from our underwritten and other offerings completed during 2009 were used to temporarily reduce borrowings outstanding under EPO's Multi-Year Revolving Credit Facility and for general partnership purposes.

Class B Units

In October 2009, in connection with the TEPPCO Merger, a privately held affiliate of EPCO exchanged a portion of its TEPPCO units, based on the 1.24 exchange rate, for 4,520,431 of our Class B units in lieu of common units. The Class B units are not entitled to regular quarterly cash distributions for the first sixteen quarters following the closing date of the merger. The Class B units automatically convert into the same number of common units on the date immediately following the payment date for the sixteenth quarterly distribution following the closing date of the merger. The Class B units are entitled to vote together with the common units as a single class on partnership matters and, except for the payment of distributions, have the same rights and privileges as our common units.

Summary of Changes in Outstanding Units

The following table summarizes changes in our outstanding units since December 31, 2006:

	COMMON UNITS	RESTRICTED COMMON UNITS	CLASS B Units	TREASURY UNITS
Balance, December 31, 2006	431,303,193	1,105,237	_	_
Common units issued in connection with DRIP and EUPP	2,056,615	_	_	_
Common units issued in connection with equity awards	244,071	738,040	_	_
Forfeiture or settlement of restricted units	_	(149,853)	_	_
Conversion of restricted units to common units	4,884	(4,884)		_
Balance, December 31, 2007	433,608,763	1,688,540	_	_
Common units issued in connection with DRIP and EUPP	5,523,946	_	_	_
Common units issued in connection with equity awards	21,905	_	_	_
Restricted units issued	_	766,200	_	_
Forfeiture or settlement of restricted units	_	(88,777)	_	_
Conversion of restricted units to common units	285,363	(285,363)	_	_
Acquisition of treasury units	(85,246)	_	_	85,246
Cancellation of treasury units		_		(85,246)
Balance, December 31, 2008	439,354,731	2,080,600	_	_
Common units issued in connection with underwritten offerings	18,927,500	_		_
Common units issued in connection with private placement	5,940,594	_	_	_
Common units issued in connection with DRIP and EUPP	12,089,920	_	_	_
Common units issued in connection with equity awards	59,638	_	_	_
Common units issued in connection with the TEPPCO Merger	126,624,302	_	_	_
Class B units issued in connection with the TEPPCO Merger	_	_	4,520,431	_
Restricted units issued	_	1,025,650	_	_
Restricted units issued in connection with the TEPPCO Merger	_	308,016	_	_
Forfeiture of restricted units	_	(411,884)	_	_
Conversion of restricted units to common units	281,500	(281,500)	_	_
Acquisition of treasury units	(75,357)	_	_	75,357
Cancellation of treasury units				(75,357)
Balance, December 31, 2009	603,202,828	2,720,882	4,520,431	

<u>Treasury Units</u>. In 2000, we and a consolidated trust (the "1999 Trust") were authorized by EPGP to repurchase up to 2,000,000 publicly-held common units under an announced buy-back program. The repurchases would be made during periods of temporary market weakness at price levels that would be accretive to our remaining unitholders. After deducting for repurchases under the program in prior periods, we and the 1999 Trust could repurchase up to 618,400 common units at December 31, 2009.

During the year ended December 31, 2009, 281,500 restricted unit awards vested and were converted to common units. Of this amount, 75,357 were sold back to us by employees to cover related withholding tax requirements. The total cost of these treasury units was approximately \$2.1 million, of which a minimal amount was allocated to our general partner. We cancelled such treasury units immediately upon acquisition.

Summary of Changes in Limited Partners' Equity

The following table details the changes in limited partners' equity since December 31, 2006:

	COMMON UNITS	RESTRICTED COMMON UNITS	CLASS B Units	TOTAL
Balance, December 31, 2006	\$ 6,320.5	\$ 9.3	\$ —	\$ 6,329.8
Net income	416.3	1.4	_	417.7
Operating lease expenses paid by EPCO	2.1	_	_	2.1
Cash distributions paid to partners	(831.2)	(2.6)	_	(833.8)
Unit option reimbursements to EPCO	(3.0)	_	_	(3.0)
Net cash proceeds from issuance of common units	60.4	_	_	60.4
Cash proceeds from exercise of unit options	7.5	_	_	7.5
Repurchase of restricted units and options	(0.5)	(1.0)	_	(1.5)
Amortization of equity awards	4.9	8.8	_	13.7
Balance, December 31, 2007	5,977.0	15.9	_	5,992.9
Net income	807.9	3.6	_	811.5
Operating lease expenses paid by EPCO	2.0	_	_	2.0
Cash distributions paid to partners	(888.8)	(3.9)	_	(892.7)
Unit option reimbursements to EPCO	(0.6)	_	_	(0.6)
Acquisition of treasury units	_	(1.9)	_	(1.9)
Net cash proceeds from issuance of common units	139.3	_	_	139.3
Cash proceeds from exercise of unit options	0.7	_	_	0.7
Amortization of equity awards	(0.6)	12.5	_	11.9
Balance, December 31, 2008	6,036.9	26.2	_	6,063.1
Net income	847.8	4.4	_	852.2
Operating lease expenses paid by EPCO	0.7	_	_	0.7
Cash distributions paid to partners	(1,064.1)	(5.2)	_	(1,069.3)
Unit option reimbursements to EPCO	(2.4)	_	_	(2.4)
Acquisition of treasury units	_	(2.1)	_	(2.1)
Common units and Class B units issued in connection with the TEPPCO Merger	2,455.6	_	118.5	2,574.1
Net cash proceeds from issuance of common units	892.8	_	_	892.8
Cash proceeds from exercise of unit options	1.7		_	1.7
Amortization of equity awards	4.5	14.4		18.9
Balance, December 31, 2009	\$ 9,173.5	\$ 37.7	\$ 118.5	\$ 9,329.7

Distributions to Partners

The percentage interest of EPGP in our quarterly cash distributions is increased after certain specified target levels of quarterly distribution rates are met. At current distribution rates, we are in the highest tier of such incentive targets. EPGP's quarterly incentive distribution thresholds are as follows:

- 2% of quarterly cash distributions up to \$0.253 per unit;
- 15% of quarterly cash distributions from \$0.253 per unit up to \$0.3085 per unit; and
- 25% of quarterly cash distributions that exceed \$0.3085 per unit.

We paid incentive distributions of \$161.3 million, \$125.9 million and \$107.4 million to EPGP during the years ended December 31, 2009, 2008 and 2007, respectively.

The following table presents our declared quarterly cash distribution rates per unit since the first quarter of 2008 and the related record and distribution payment dates. The quarterly cash distribution rates per unit correspond to the fiscal quarters indicated. Actual cash distributions are paid within 45 days after the end of such fiscal quarter.

	DISTRIBUTION PER UNIT	RECORD DATE	PAYMENT DATE
2008			
1st Quarter	\$0.5075	Apr. 30, 2008	May 7, 2008
2nd Quarter	\$0.5150	Jul. 31, 2008	Aug. 7, 2008
3rd Quarter	\$0.5225	Oct. 31, 2008	Nov. 12, 2008
4th Quarter	\$0.5300	Jan. 30, 2009	Feb. 9, 2009
2009			
1st Quarter	\$0.5375	Apr. 30, 2009	May 8, 2009
2nd Quarter	\$0.5450	Jul. 31, 2009	Aug. 7, 2009
3rd Quarter	\$0.5525	Oct. 30, 2009	Nov. 5, 2009
4th Quarter	\$0.5600	Jan. 29, 2010	Feb. 4, 2010

Accumulated Other Comprehensive Loss

AOCI primarily includes the effective portion of the gain or loss on derivative instruments designated and qualified as a cash flow hedge, foreign currency adjustments and minimum pension liability adjustments. Amounts accumulated in OCI from cash flow hedges are reclassified into earnings in the same period(s) in which the hedged forecasted transactions (such as a forecasted forward sale of NGLs) affect earnings. If it becomes probable that the forecasted transaction will not occur, the net gain or loss in AOCI must be immediately reclassified.

The following table presents the components of AOCI at the dates indicated:

	AI DECEMBER 31,		
	 2009		2008
Commodity derivative instruments (1)	\$ 0.5	\$	(114.1)
Interest rate derivative instruments (1)	(12.5)		(41.9)
Foreign currency derivative instruments (1)	0.4		10.6
Foreign currency translation adjustment (2)	8.0		(1.3)
Pension and postretirement benefit plans	 (8.0)		(8.0)
Subtotal	(11.6)		(147.5)
Amount attributable to noncontrolling interest	 3.2		50.3
Total AOCI in partners' equity	\$ (8.4)	\$	(97.2)

⁽¹⁾ See Note 6 for additional information regarding these components of AOCI.

Noncontrolling Interest

Prior to the completion of the TEPPCO Merger, effective October 26, 2009, we accounted for the former owners' interest in TEPPCO and TEPPCO GP as noncontrolling interest. Under this method of presentation, all pre-merger revenues and expenses of TEPPCO and TEPPCO GP are included in net income, and the former owners' share of the income of TEPPCO and TEPPCO GP is allocated to net income attributable to noncontrolling interest. In addition, the former owners' share of the net assets of TEPPCO and TEPPCO GP are presented as noncontrolling interest, a component of equity, on our Consolidated Balance Sheets.

⁽²⁾ Relates to transactions of our Canadian NGL marketing subsidiary.

The following table presents the components of noncontrolling interest as presented on our Consolidated Balance Sheets at the dates indicated:

	AT DECEMBER 31,			
		2009	2008	
Former owners of TEPPCO (1)	\$	_	\$ 2,827.6	
Limited partners of Duncan Energy Partners:				
Third-party owners of Duncan Energy Partners (2)		414.3	281.1	
Related party owners of Duncan Energy Partners		1.7	_	
Joint venture partners (3)		117.4	148.0	
AOCI attributable to noncontrolling interest		(3.2)	(50.3)	
Total noncontrolling interest	\$	530.2	\$ 3,206.4	

- (1) Represents former ownership interests in TEPPCO and TEPPCO GP (see Note 1, "TEPPCO Merger and Basis of Presentation"). This amount excludes AOCI attributable to former owners of TEPPCO.
- (2) Represents non-affiliate public unitholders of Duncan Energy Partners. The increase in noncontrolling interest between years is attributable to Duncan Energy Partners' equity offering in June 2009.
- (3) Represents third-party ownership interests in joint ventures that we consolidate, including Seminole, Tri-States Pipeline L.L.C., Independence Hub LLC and Wilprise Pipeline Company LLC. The balance at December 31, 2008 included \$35.6 million related to Oiltanking's ownership interest in TOPS, from which our subsidiaries dissociated in April 2009 (see Note 8).

The following table presents the components of net income attributable to noncontrolling interest as presented on our Statements of Consolidated Operations for the periods indicated:

	FOR YEAR ENDED DECEMBER 31,					
	2009		2008			2007
Former owners of TEPPCO (1)	\$	66.5	\$	193.6	\$	273.8
Limited partners of Duncan Energy Partners (2)		31.3		17.3		13.9
Joint venture partners		26.4		24.0		16.7
Total	\$	124.2	\$	234.9	\$	304.4

- (1) Represents the allocation of earnings to the former owners of TEPPCO.
- (2) Represents the allocation of Duncan Energy Partners earnings to its third-party unitholders.

The following table presents cash distributions paid to and cash contributions received from noncontrolling interests as presented on our Statements of Consolidated Cash Flows and Statements of Consolidated Equity for the periods indicated:

	FOR YEAR ENDED DECEMBER 31,			
	2009	2008	2007	
Cash distributions paid to noncontrolling interests:	\$ 274.5	\$ 328.0	\$ 294.4	
Limited partners of TEPPCO Limited partners of Duncan Energy Partners	\$ 274.5 33.7	\$ 326.0 24.8	\$ 294.4 15.8	
Joint venture partners	31.8	31.1	16.6	
Total cash distributions paid to noncontrolling interests	\$ 340.0	\$ 383.9	\$ 326.8	
Cash contributions from noncontrolling interests:				
Limited partners of TEPPCO	\$ 3.5	\$ 275.9	\$ 1.7	
Limited partners of Duncan Energy Partners	137.4	_	290.5	
Joint venture partners	(2.2)	35.6	12.5	
Total cash contributions from noncontrolling interests	\$ 138.7	\$ 311.5	\$ 304.7	

Distributions paid to the limited partners of Duncan Energy Partners and former owners of TEPPCO primarily represent the quarterly cash distributions paid by these entities to their unitholders.

Contributions received from limited partners of TEPPCO and Duncan Energy Partners primarily represent net cash proceeds each entity received from common unit offerings. In September 2008, TEPPCO sold 9,200,000 of its common units in an underwritten equity offering, which generated net cash proceeds of \$257.0 million. In February 2007, Duncan Energy Partners received approximately \$291.0 million of net cash proceeds in connection with its initial public offering. In June and July 2009, Duncan Energy Partners issued an aggregate 8,943,400 of its common units, which generated net cash proceeds of approximately \$137.4 million. Duncan Energy Partners used the net cash proceeds from its issuance of these units to repurchase and cancel an equal number of its common units beneficially owned by EPO.

NOTE 14. BUSINESS SEGMENTS

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

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

We define total segment gross operating margin as operating income before: (i) depreciation, amortization and accretion expense; (ii) non-cash consolidated asset impairment charges; (iii) operating lease expenses for which we do not have the payment obligation; (iv) gains and losses from asset sales and related transactions; and (v) general and administrative costs. Gross operating margin by segment is calculated by subtracting segment operating costs and expenses (net of the adjustments noted above) from segment revenues, with both segment totals before the elimination of intercompany transactions. In accordance with GAAP, intercompany accounts and transactions are eliminated in consolidation. Gross operating margin is exclusive of other income and expense transactions, provision for income taxes, the cumulative effect of changes in accounting principles and extraordinary charges. Gross operating margin is presented on a 100% basis before the allocation of earnings to noncontrolling interests.

Segment revenues include intersegment and intrasegment transactions, which are generally based on transactions made at market-based rates. Our consolidated revenues reflect the elimination of intercompany (both intersegment and intrasegment) transactions.

We include equity in income of unconsolidated affiliates in our measurement of segment gross operating margin and operating income. Our equity investments with industry partners are a vital component of our business strategy. They are a means by which we conduct our operations to align our interests with those of our customers and/or suppliers. 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 standalone basis. Many of these businesses perform supporting or complementary roles to our other business operations.

Our integrated midstream energy asset system (including the midstream energy assets of our equity method investees) provides services to producers and consumers of natural gas, NGLs, crude oil, refined products and certain petrochemicals. In general, hydrocarbons enter our asset system in a number of ways, such as an offshore natural gas or crude oil pipeline, an offshore platform, a natural gas processing plant, an onshore natural gas gathering pipeline, an NGL fractionator, an NGL storage facility or an NGL transportation or distribution pipeline.

Many of our equity investees are included within our integrated midstream asset system. For example, we have ownership interests in several offshore natural gas, refined products and crude oil pipelines. Other examples include our use of the Promix NGL fractionator to process mixed NGLs extracted by our gas plants. The fractionated NGLs we receive from Promix can then be sold in our NGL marketing activities. Additionally, our use of the Centennial pipeline, which loops the refined products pipeline system between Beaumont, Texas and southern Illinois, permits effective supply of product to points south of Illinois as well as incremental product supply capacity to midcontinent markets downstream of southern Illinois. Given the integral nature of our equity method investees to our operations, we believe the presentation of earnings from such investees as a component of gross operating margin and operating income is meaningful and appropriate.

Substantially all of our consolidated revenues are earned in the United States and derived from a wide customer base. The majority of our plant-based operations are located in Texas, Louisiana, Mississippi, New Mexico, Colorado and Wyoming. Our natural gas, NGL, refined products and crude oil pipelines are located in a number of regions of the United States including: (i) the Gulf of Mexico offshore Texas, Louisiana and onshore in Colorado; (ii) the south and southeastern United States, (primarily in Texas, Louisiana, Mississippi and Alabama); (iii) the Midwestern and northeastern United States; and (iv) certain regions of the central and western United States, including the Rocky Mountains. Our marketing activities are headquartered in Houston, Texas and Oklahoma City, Oklahoma and serve customers in a number of regions of the United States including the Gulf Coast, West Coast and Mid-Continent areas.

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

We consolidate the financial statements of Duncan Energy Partners with those of our own. As a result, our consolidated gross operating margin amounts include 100% of the gross operating margin amounts of Duncan Energy Partners.

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

Revenues 2009 2008 2007 Less: Operating costs and expenses \$ 25,510.9 \$ 35,469.6 \$ 26,713.8 Add: Equity in income of unconsolidated affiliates (23,565.8) (33,618.9) (25,402.1)		FOR YEAR ENDED DECEMBER 31,				31,	
Less: Operating costs and expenses (23,565.8) (33,618.9) (25,402.1)		2	2009		2008		2007
	renues	\$ 25	5,510.9	\$	35,469.6	\$	26,713.8
Add: Equity in income of unconsolidated affiliates 51.2 34.9 10.5	s: Operating costs and expenses	(23	3,565.8)		(33,618.9)		(25,402.1)
	I: Equity in income of unconsolidated affiliates		51.2		34.9		10.5
Depreciation, amortization and accretion in operating costs and expenses (1) 809.3 725.4 647.9	, ,		809.3		725.4		647.9
Impairment charges in operating costs and expenses 33.5 — — —	Impairment charges in operating costs and expenses		33.5		_		_
Operating lease expenses paid by EPCO 0.7 2.0 2.1	Operating lease expenses paid by EPCO		0.7		2.0		2.1
Gain from asset sales and related transactions in operating costs and expenses (2) — (4.0) (7.8)	1 9		_		(4.0)		(7.8)
Total segment gross operating margin \$ 2,839.8 \$ 2,609.0 \$ 1,964.4	al segment gross operating margin	\$ 2	2,839.8	\$	2,609.0	\$	1,964.4

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

⁽²⁾ Amount is a component of "Gain from asset sales and related transactions" as presented on the Statements of Consolidated Cash Flows.

The following table shows a reconciliation of our total segment gross operating margin to operating income and income before provision for income taxes for the periods indicated:

	FOR YEAR ENDED DECEMBER 31,			
	2009	2008	2007	
Total segment gross operating margin	\$ 2,839.8	\$ 2,609.0	\$ 1,964.4	
Adjustments to reconcile total segment gross operating margin				
to operating income:				
Depreciation, amortization and accretion in operating costs and expenses	(809.3)	(725.4)	(647.9)	
Impairment charges in operating costs and expenses	(33.5)			
Operating lease expenses paid by EPCO	(0.7)	(2.0)	(2.1)	
Gain from asset sales and related transactions in operating costs and expenses	_	4.0	7.8	
General and administrative costs	(172.3)	(137.2)	(127.2)	
Operating income	1,824.0	1,748.4	1,195.0	
Other expense, net	(643.6)	(528.5)	(341.3)	
Income before provision for income taxes	\$ 1,180.4	\$ 1,219.9	\$ 853.7	

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

		RE	PORTABLE SEGM	ENTS			
	NGL PIPELINES & SERVICES	ONSHORE Natural gas Pipelines & Services	ONSHORE CRUDE OIL PIPELINES & SERVICES	OFFSHORE PIPELINES & SERVICES	PETROCHEMICAL & REFINED PRODUCTS SERVICES	ADJUSTMENTS AND ELIMINATIONS	CONSOLIDATED Totals
Revenues from third parties:							
Year ended December 31, 2009	\$11,928.3	\$ 2,938.7	\$ 7,191.2	\$ 332.9	\$ 2,520.8	\$ —	\$24,911.9
Year ended December 31, 2008	14,715.8	3,407.2	12,763.8	260.3	3,307.1	_	34,454.2
Year ended December 31, 2007	12,149.2	2,044.0	9,103.7	222.6	2,609.1	_	26,128.6
Revenues from related parties:							
Year ended December 31, 2009	380.7	211.2	(0.2)	7.0	0.3	_	599.0
Year ended December 31, 2008	598.0	409.2	_	8.1	0.1	_	1,015.4
Year ended December 31, 2007	301.5	281.9	0.1	1.2	0.5	_	585.2
Intersegment and intrasegment revenues	S:						
Year ended December 31, 2009	6,865.5	515.3	47.6	1.3	612.3	(8,042.0)	_
Year ended December 31, 2008	8,091.7	881.6	75.1	1.4	663.3	(9,713.1)	_
Year ended December 31, 2007	5,436.3	205.5	48.6	2.0	522.6	(6,215.0)	_
Total revenues:							
Year ended December 31, 2009	19,174.5	3,665.2	7,238.6	341.2	3,133.4	(8,042.0)	25,510.9
Year ended December 31, 2008	23,405.5	4,698.0	12,838.9	269.8	3,970.5	(9,713.1)	35,469.6
Year ended December 31, 2007	17,887.0	2,531.4	9,152.4	225.8	3,132.2	(6,215.0)	26,713.8
Equity in income of unconsolidated affili	ates:						
Year ended December 31, 2009	11.3	4.9	9.3	36.9	(11.2)		51.2
Year ended December 31, 2008	1.4	1.6	11.7	33.7	(13.5)	_	34.9
Year ended December 31, 2007	7.1	0.2	2.6	12.6	(12.0)	_	10.5
Gross operating margin:							
Year ended December 31, 2009	1,628.7	501.5	164.4	180.5	364.7		2,839.8
Year ended December 31, 2008	1,325.0	589.9	132.2	187.0	374.9	_	2,609.0
Year ended December 31, 2007	848.0	493.2	109.6	171.6	342.0	_	1,964.4
Segment assets:							
At December 31, 2009	7,191.2	6,918.7	865.3	2,121.4	3,359.0	1,207.3	21,662.9
At December 31, 2008	6,459.3	6,118.8	883.0	2,061.8	3,308.9	2,015.4	20,847.2
At December 31, 2007	5,488.5	5,502.3	858.8	2,152.3	2,631.9	1,588.3	18,222.1
Property, plant and equipment (see Note	8):						
At December 31, 2009	6,392.8	6,074.6	377.3	1,480.9	2,156.3	1,207.3	17,689.2
At December 31, 2008	5,622.4	5,223.6	386.9	1,394.5	2,090.0	2,015.4	16,732.8
At December 31, 2007	4,770.4	4,577.4	363.7	1,452.6	1,556.7	1,588.3	14,309.1
Investments in unconsolidated affiliates	(see Note 9):						
At December 31, 2009	141.6	32.0	178.5	456.9	81.6	_	890.6
At December 31, 2008	144.3	25.9	186.2	469.0	86.5	_	911.9
At December 31, 2007	117.0	3.5	184.8	484.6	95.7	_	885.6
Intangible assets, net (see Note 11):							
At December 31, 2009	315.6	527.2	6.5	101.5	114.0	_	1,064.8
At December 31, 2008	351.4	584.4	6.9	116.2	124.0	_	1,182.9
At December 31, 2007	375.1	636.5	7.3	133.0	62.2	_	1,214.1
Goodwill (see Note 11):	0.011	230.0	, .5	100.0	52.2		_,
At December 31, 2009	341.2	284.9	303.0	82.1	1,007.1		2,018.3
At December 31, 2008	341.2	284.9	303.0	82.1	1,007.1		2,010.5
At December 31, 2007	226.0	284.9	303.0	82.1	917.3	_	1,813.3
At December 31, 2007	220.0	204.9	303.0	02.1	517.3	_	1,013.3

Our consolidated revenues are derived from a wide customer base. During 2009, our largest non-affiliated customer based on revenues was Shell Oil Company and its affiliates, which accounted for 9.8% of our revenues. During 2008 and 2007, our largest non-affiliated customer based on revenues was Valero Energy Corporation and its affiliates, which accounted for 11.2% and 8.9%, respectively, of our revenues.

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

Roll Pipelines & Services: Sales of NGLs \$11,598.9 \$14,573.5 \$11,701.3 Sales of Other petroleum and related products 1.8 2.4 3.0 Midstream services 708.3 737.9 746.4 Total 12,309.0 15,313.8 12,450.7 Onsher Matural Gas Pipelines & Services: Sales of natural gas 2,410.5 3,083.1 1,676.7 Midstream services 739.4 733.3 649.2 Total 3,149.9 3,816.4 2,325.9 Midstream services 7,110.6 12,696.2 9,048.5 Total 7,110.6 12,696.2 9,048.5 Midstream services 80.4 67.6 55.3 Total 7,190.6 12,696.2 9,048.5 Sales of natural gas 1.5 2.2 8 3.2 Total 5.3 1.1 1.2 1.2 2.2 8 3.2 2.2 2.2 2.2 2.2 2.2 2.2 2.2 2.2		FOR YEAR ENDED DECEMBER 31,					
Sales of NGLs \$ 11,598.9 \$ 14,573.5 \$ 11,701.3 Sales of other petroleum and related products 1.8 2.4 3.0 Midstream services 708.3 737.9 746.4 Total 12,309.0 15,313.8 12,450.7 Onshore Natural Gas Pipelines & Services: Sales of natural gas 2,410.5 3,083.1 1,676.7 Midstream services 739.4 733.3 649.2 Total 3,149.9 3,816.4 2,325.9 Onshore Crude Oil Pipelines & Services: 80.4 67.6 55.3 Total 7,110.6 12,696.2 9,048.5 Midstream services 80.4 67.6 55.3 Total 7,191.0 12,763.8 9,103.8 Offshore Pipelines & Services: 80.4 67.6 55.3 Total 5.3 11.1 12.1 Midstream services 333.4 254.5 208.5 Total 339.9 268.4 223.8 Petrochemical & Refined Products Services: 1,9			2009		2008		2007
Sales of other petroleum and related products 1.8 2.4 3.0 Midstream services 708.3 737.9 746.4 Total 12,309.0 15,313.8 12,450.7 Onshore Natural Gas Pipelines & Services: Sales of natural gas 2,410.5 3,083.1 1,676.7 Midstream services 739.4 733.3 649.2 Total 3,149.9 3,816.4 2,325.9 Onshore Crude Oil Pipelines & Services: 80.4 67.6 55.3 Total 7,110.6 12,696.2 9,048.5 Midstream services 80.4 67.6 55.3 Total 7,191.0 12,763.8 9,103.8 Offshore Pipelines & Services: 80.4 67.6 55.3 Total 5.3 1.1.1 12.763.8 9,103.8 Offshore Pipelines & Services: 33.3 2.54.5 208.5 Sales of natural gas 1.2 2.8 3.2 Sales of crude oil 5.3 11.1 12.1 Midstream services	NGL Pipelines & Services:						
Midstream services 708.3 737.9 746.4 Total 12,309.0 15,313.8 12,450.7 Onshore Natural Gas Pipelines & Services: Sales of natural gas 2,410.5 3,083.1 1,676.7 Midstream services 739.4 733.3 649.2 Total 3,149.9 3,816.4 2,325.9 Onshore Crude Oil Pipelines & Services: Sales of crude Oil Pipelines & Services: 80.4 67.6 55.3 Total 7,110.6 12,696.2 9,048.5 Midstream services 80.4 67.6 55.3 Total 7,191.0 12,763.8 9,103.8 Offshore Pipelines & Services: Sales of natural gas 1.2 2.8 3.2 Sales of crude oil 5.3 11.1 12.1 Midstream services 333.4 254.5 208.5 Total 339.9 268.4 223.8 Petrochemical & Refined Products Services: Sales of other petroleum and related products 1,991.8<	Sales of NGLs	\$	11,598.9	\$	14,573.5	\$	11,701.3
Total 12,309.0 15,313.8 12,450.7 Onshore Natural Gas Pipelines & Services: 3,083.1 1,676.7 Midstream services 739.4 733.3 649.2 Total 3,149.9 3,816.4 2,325.9 Onshore Crude Oil Pipelines & Services: 3,149.9 3,816.4 2,325.9 Onshore Crude Oil Pipelines & Services: 80.4 67.6 55.3 Midstream services 80.4 67.6 55.3 Total 7,191.0 12,763.8 9,103.8 Offshore Pipelines & Services: 80.4 67.6 55.3 Total 5.3 1.1 12.1 Midstream services of crude oil 5.3 11.1 12.1 Midstream services 333.4 254.5 208.5 Total 339.9 268.4 223.8 Petrochemical & Refined Products Services: 1,991.8 2,757.6 2,207.2 Midstream services 529.3 549.6 402.4 Total 2,521.1 3,307.2 2,609.6	Sales of other petroleum and related products		1.8		2.4		3.0
Onshore Natural Gas Pipelines & Services: Sales of natural gas 2,410.5 3,083.1 1,676.7 Midstream services 739.4 733.3 649.2 Total 3,149.9 3,816.4 2,325.9 Onshore Crude Oil Pipelines & Services: Sales of crude oil 7,110.6 12,696.2 9,048.5 Midstream services 80.4 67.6 55.3 Total 7,191.0 12,763.8 9,103.8 Offshore Pipelines & Services: Sales of natural gas 1.2 2.8 3.2 Sales of crude oil 5.3 11.1 12.1 Midstream services 333.4 254.5 208.5 Total 339.9 268.4 223.8 Petrochemical & Refined Products Services: Sales of other petroleum and related products 1,991.8 2,757.6 2,207.2 Midstream services 529.3 549.6 402.4 Total 2,521.1 3,307.2 2,609.6 Total consolidated revenues	Midstream services		708.3		737.9		746.4
Onshore Natural Gas Pipelines & Services: Sales of natural gas 2,410.5 3,083.1 1,676.7 Midstream services 739.4 733.3 649.2 Total 3,149.9 3,816.4 2,325.9 Onshore Crude Oil Pipelines & Services: Sales of crude oil 7,110.6 12,696.2 9,048.5 Midstream services 80.4 67.6 55.3 Total 7,191.0 12,763.8 9,103.8 Offshore Pipelines & Services: Sales of natural gas 1.2 2.8 3.2 Sales of crude oil 5.3 11.1 12.1 Midstream services 333.4 254.5 208.5 Total 339.9 268.4 223.8 Petrochemical & Refined Products Services: Sales of other petroleum and related products 1,991.8 2,757.6 2,207.2 Midstream services 529.3 549.6 402.4 Total 2,521.1 3,307.2 2,609.6 Total consolidated revenues	Total		12,309.0		15,313.8		12,450.7
Midstream services 739.4 733.3 649.2 Total 3,149.9 3,816.4 2,325.9 Onshore Crude Oil Pipelines & Services: Sales of crude oil 7,110.6 12,696.2 9,048.5 Midstream services 80.4 67.6 55.3 Total 7,191.0 12,763.8 9,103.8 Offshore Pipelines & Services: Sales of natural gas 1.2 2.8 3.2 Sales of crude oil 5.3 11.1 12.1 Midstream services 333.4 254.5 208.5 Total 339.9 268.4 223.8 Petrochemical & Refined Products Services: Sales of other petroleum and related products 1,991.8 2,757.6 2,207.2 Midstream services 529.3 549.6 402.4 Total 2,521.1 3,307.2 2,609.6 Total consolidated revenues 25,510.9 35,469.6 26,713.8 Consolidated costs and expenses: Cost of sales for our marketing activities <td>Onshore Natural Gas Pipelines & Services:</td> <td></td> <td></td> <td></td> <td></td> <td></td> <td></td>	Onshore Natural Gas Pipelines & Services:						
Total 3,149.9 3,816.4 2,325.9 Onshore Crude Oil Pipelines & Services: 3,149.9 3,816.4 2,325.9 Sales of crude oil 7,110.6 12,696.2 9,048.5 Midstream services 80.4 67.6 55.3 Total 7,191.0 12,763.8 9,103.8 Offshore Pipelines & Services: 332.8 22.8 3.2 Sales of natural gas 1.2 2.8 3.2 Sales of crude oil 5.3 11.1 12.1 Midstream services 333.4 254.5 208.5 Total 339.9 268.4 223.8 Petrochemical & Refined Products Services: Sales of other petroleum and related products 1,991.8 2,757.6 2,207.2 Midstream services 529.3 549.6 402.4 Total 2,521.1 3,307.2 2,609.6 Total consolidated revenues 25,510.9 35,469.6 26,713.8 Consolidated costs and expenses: Cost of sales for our marketing activities 18,65	Sales of natural gas		2,410.5		3,083.1		1,676.7
Onshore Crude Oil Pipelines & Services: Sales of crude oil 7,110.6 12,696.2 9,048.5 Midstream services 80.4 67.6 55.3 Total 7,191.0 12,763.8 9,103.8 Offshore Pipelines & Services: Sales of natural gas 1.2 2.8 3.2 Sales of crude oil 5.3 11.1 12.1 Midstream services 333.4 254.5 208.5 Total 339.9 268.4 223.8 Petrochemical & Refined Products Services: Sales of other petroleum and related products 1,991.8 2,757.6 2,207.2 Midstream services 529.3 549.6 402.4 Total 2,521.1 3,307.2 2,609.6 Total consolidated revenues \$25,510.9 \$35,469.6 \$26,713.8 Consolidated costs and expenses: Cost of sales for our marketing activities \$18,656.7 \$28,250.2 \$21,142.5 Depreciation, amortization a	Midstream services		739.4		733.3		649.2
Sales of crude oil 7,110.6 12,696.2 9,048.5 Midstream services 80.4 67.6 55.3 Total 7,191.0 12,763.8 9,103.8 Offshore Pipelines & Services: Sales of natural gas 1.2 2.8 3.2 Sales of crude oil 5.3 11.1 12.1 Midstream services 333.4 254.5 208.5 Total 339.9 268.4 223.8 Petrochemical & Refined Products Services: Sales of other petroleum and related products 1,991.8 2,757.6 2,207.2 Midstream services 529.3 549.6 402.4 Total 2,521.1 3,307.2 2,609.6 Total consolidated revenues \$25,510.9 \$35,469.6 \$26,713.8 Consolidated costs and expenses: Cost of sales for our marketing activities \$18,656.7 \$28,250.2 \$21,142.5 Depreciation, amortization and accretion 809.3 725.4 647.9 Gain on sale of assets and related transactions —	Total		3,149.9		3,816.4		2,325.9
Midstream services 80.4 67.6 55.3 Total 7,191.0 12,763.8 9,103.8 Offshore Pipelines & Services: Sales of natural gas 1.2 2.8 3.2 Sales of crude oil 5.3 11.1 12.1 Midstream services 333.4 254.5 208.5 Total 339.9 268.4 223.8 Petrochemical & Refined Products Services: Sales of other petroleum and related products 1,991.8 2,757.6 2,207.2 Midstream services 529.3 549.6 402.4 Total 2,521.1 3,307.2 2,609.6 Total consolidated revenues \$25,510.9 \$35,469.6 \$26,713.8 Consolidated costs and expenses Cost of sales for our marketing activities \$18,656.7 \$28,250.2 \$21,142.5 Depreciation, amortization and accretion 809.3 725.4 647.9 Gain on sale of assets and related transactions — (4.0) (7.8) Non-cash impairment charges 33.5	Onshore Crude Oil Pipelines & Services:						
Total 7,191.0 12,763.8 9,103.8 Offshore Pipelines & Services: Sales of natural gas 1.2 2.8 3.2 Sales of crude oil 5.3 11.1 12.1 Midstream services 333.4 254.5 208.5 Total 339.9 268.4 223.8 Petrochemical & Refined Products Services: Sales of other petroleum and related products 1,991.8 2,757.6 2,207.2 Midstream services 529.3 549.6 402.4 Total 2,521.1 3,307.2 2,609.6 Total consolidated revenues \$25,510.9 \$35,469.6 \$26,713.8 Consolidated costs and expenses: Cost of sales for our marketing activities \$18,656.7 \$28,250.2 \$21,142.5 Depreciation, amortization and accretion 809.3 725.4 647.9 Gain on sale of assets and related transactions — (4.0) (7.8) Non-cash impairment charges 33.5 — —	Sales of crude oil		7,110.6		12,696.2		9,048.5
Offshore Pipelines & Services: Sales of natural gas 1.2 2.8 3.2 Sales of crude oil 5.3 11.1 12.1 Midstream services 333.4 254.5 208.5 Total 339.9 268.4 223.8 Petrochemical & Refined Products Services: Sales of other petroleum and related products 1,991.8 2,757.6 2,207.2 Midstream services 529.3 549.6 402.4 Total 2,521.1 3,307.2 2,609.6 Total consolidated revenues \$25,510.9 \$35,469.6 \$26,713.8 Consolidated costs and expenses: Cost of sales for our marketing activities \$18,656.7 \$28,250.2 \$21,142.5 Depreciation, amortization and accretion 809.3 725.4 647.9 Gain on sale of assets and related transactions — (4.0) (7.8) Non-cash impairment charges 33.5 — —	Midstream services		80.4		67.6		55.3
Sales of natural gas 1.2 2.8 3.2 Sales of crude oil 5.3 11.1 12.1 Midstream services 333.4 254.5 208.5 Total 339.9 268.4 223.8 Petrochemical & Refined Products Services: Sales of other petroleum and related products 1,991.8 2,757.6 2,207.2 Midstream services 529.3 549.6 402.4 Total 2,521.1 3,307.2 2,609.6 Total consolidated revenues \$25,510.9 \$35,469.6 \$26,713.8 Consolidated costs and expenses: Cost of sales for our marketing activities \$18,656.7 \$28,250.2 \$21,142.5 Depreciation, amortization and accretion 809.3 725.4 647.9 Gain on sale of assets and related transactions — (4.0) (7.8) Non-cash impairment charges 33.5 — —	Total		7,191.0		12,763.8		9,103.8
Sales of crude oil 5.3 11.1 12.1 Midstream services 333.4 254.5 208.5 Total 339.9 268.4 223.8 Petrochemical & Refined Products Services: Sales of other petroleum and related products 1,991.8 2,757.6 2,207.2 Midstream services 529.3 549.6 402.4 Total 2,521.1 3,307.2 2,609.6 Total consolidated revenues \$25,510.9 \$35,469.6 \$26,713.8 Consolidated costs and expenses: Cost of sales for our marketing activities \$18,656.7 \$28,250.2 \$21,142.5 Depreciation, amortization and accretion 809.3 725.4 647.9 Gain on sale of assets and related transactions — (4.0) (7.8) Non-cash impairment charges 33.5 — —	Offshore Pipelines & Services:						
Midstream services 333.4 254.5 208.5 Total 339.9 268.4 223.8 Petrochemical & Refined Products Services: Sales of other petroleum and related products 1,991.8 2,757.6 2,207.2 Midstream services 529.3 549.6 402.4 Total 2,521.1 3,307.2 2,609.6 Total consolidated revenues Consolidated costs and expenses Operating costs and expenses: Cost of sales for our marketing activities \$ 18,656.7 \$ 28,250.2 \$ 21,142.5 Depreciation, amortization and accretion 809.3 725.4 647.9 Gain on sale of assets and related transactions — (4.0) (7.8) Non-cash impairment charges 33.5 — —	Sales of natural gas		1.2		2.8		3.2
Total 339.9 268.4 223.8 Petrochemical & Refined Products Services: Sales of other petroleum and related products 1,991.8 2,757.6 2,207.2 Midstream services 529.3 549.6 402.4 Total 2,521.1 3,307.2 2,609.6 Total consolidated revenues Consolidated costs and expenses Operating costs and expenses: Cost of sales for our marketing activities \$ 18,656.7 \$ 28,250.2 \$ 21,142.5 Depreciation, amortization and accretion 809.3 725.4 647.9 Gain on sale of assets and related transactions — (4.0) (7.8) Non-cash impairment charges 33.5 — —	Sales of crude oil		5.3		11.1		12.1
Petrochemical & Refined Products Services: Sales of other petroleum and related products 1,991.8 2,757.6 2,207.2 Midstream services 529.3 549.6 402.4 Total 2,521.1 3,307.2 2,609.6 Total consolidated revenues \$ 25,510.9 \$ 35,469.6 \$ 26,713.8 Consolidated costs and expenses Operating costs and expenses: Cost of sales for our marketing activities \$ 18,656.7 \$ 28,250.2 \$ 21,142.5 Depreciation, amortization and accretion 809.3 725.4 647.9 Gain on sale of assets and related transactions — (4.0) (7.8) Non-cash impairment charges 33.5 — —	Midstream services		333.4		254.5		208.5
Sales of other petroleum and related products 1,991.8 2,757.6 2,207.2 Midstream services 529.3 549.6 402.4 Total 2,521.1 3,307.2 2,609.6 Total consolidated revenues \$ 25,510.9 \$ 35,469.6 \$ 26,713.8 Consolidated costs and expenses Operating costs and expenses: Cost of sales for our marketing activities \$ 18,656.7 \$ 28,250.2 \$ 21,142.5 Depreciation, amortization and accretion 809.3 725.4 647.9 Gain on sale of assets and related transactions — (4.0) (7.8) Non-cash impairment charges 33.5 — —	Total		339.9		268.4		223.8
Midstream services 529.3 549.6 402.4 Total 2,521.1 3,307.2 2,609.6 Total consolidated revenues \$ 25,510.9 \$ 35,469.6 \$ 26,713.8 Consolidated costs and expenses Operating costs and expenses: Cost of sales for our marketing activities \$ 18,656.7 \$ 28,250.2 \$ 21,142.5 Depreciation, amortization and accretion 809.3 725.4 647.9 Gain on sale of assets and related transactions — (4.0) (7.8) Non-cash impairment charges 33.5 — —	Petrochemical & Refined Products Services:						
Total 2,521.1 3,307.2 2,609.6 Total consolidated revenues \$ 25,510.9 \$ 35,469.6 \$ 26,713.8 Consolidated costs and expenses Operating costs and expenses: \$ 28,250.2 \$ 21,142.5 Cost of sales for our marketing activities \$ 18,656.7 \$ 28,250.2 \$ 21,142.5 Depreciation, amortization and accretion 809.3 725.4 647.9 Gain on sale of assets and related transactions — (4.0) (7.8) Non-cash impairment charges 33.5 — —	Sales of other petroleum and related products		1,991.8		2,757.6		2,207.2
Total consolidated revenues \$ 25,510.9 \$ 35,469.6 \$ 26,713.8 Consolidated costs and expenses Operating costs and expenses: Cost of sales for our marketing activities \$ 18,656.7 \$ 28,250.2 \$ 21,142.5 Depreciation, amortization and accretion 809.3 725.4 647.9 Gain on sale of assets and related transactions — (4.0) (7.8) Non-cash impairment charges 33.5 — —	Midstream services		529.3		549.6		402.4
Consolidated costs and expenses Operating costs and expenses: Cost of sales for our marketing activities \$ 18,656.7 \$ 28,250.2 \$ 21,142.5 Depreciation, amortization and accretion 809.3 725.4 647.9 Gain on sale of assets and related transactions — (4.0) (7.8) Non-cash impairment charges 33.5 — —	Total		2,521.1		3,307.2		2,609.6
Operating costs and expenses: Cost of sales for our marketing activities \$ 18,656.7 \$ 28,250.2 \$ 21,142.5 Depreciation, amortization and accretion 809.3 725.4 647.9 Gain on sale of assets and related transactions — (4.0) (7.8) Non-cash impairment charges 33.5 — —	Total consolidated revenues	\$	25,510.9	\$	35,469.6	\$	26,713.8
Operating costs and expenses: Cost of sales for our marketing activities \$ 18,656.7 \$ 28,250.2 \$ 21,142.5 Depreciation, amortization and accretion 809.3 725.4 647.9 Gain on sale of assets and related transactions — (4.0) (7.8) Non-cash impairment charges 33.5 — —	Cancalidated agets and expenses						
Cost of sales for our marketing activities \$ 18,656.7 \$ 28,250.2 \$ 21,142.5 Depreciation, amortization and accretion 809.3 725.4 647.9 Gain on sale of assets and related transactions — (4.0) (7.8) Non-cash impairment charges 33.5 — —	•						
Depreciation, amortization and accretion809.3725.4647.9Gain on sale of assets and related transactions—(4.0)(7.8)Non-cash impairment charges33.5——		Ф	19 656 7	Ф	28 250 2	Ф	21 1/2 5
Gain on sale of assets and related transactions — (4.0) (7.8) Non-cash impairment charges 33.5 — —	8	φ	,	φ	,	φ	,
Non-cash impairment charges 33.5 — —	·		005.5				
			33 5		(+.0)		(7.5)
other operating costs and expenses 4,000.5 4,047.5 5,019.5					16173		3 619 5
General and administrative costs 172.3 137.2 127.2			,		,		,
Total consolidated costs and expenses \$ 23,738.1 \$ 33,756.1 \$ 25,529.3		\$		\$		\$	

The following information is provided to reconcile total revenues and total gross operating margin for the years ended December 31, 2008 and 2007, as currently presented, with those we previously presented.

	FOR YEAR ENDED DECEMBER 31,			
	2008	2007		
Total revenues, as previously reported	\$ 21,905.6	\$ 16,950.1		
Revenues from TEPPCO	13,532.9	9,658.1		
Revenues from Jonah (1)	232.8	204.1		
Eliminations (2)	(201.7)	(98.5)		
Total revenues, as currently reported	\$ 35,469.6	\$ 26,713.8		
Total segment gross operating margin, as previously reported	\$ 2,057.4	\$ 1,492.1		
Gross operating margin from TEPPCO	501.0	434.8		
Gross operating margin from Jonah	157.6	125.4		
Eliminations (3)	(107.0)	(87.9)		
Total segment gross operating margin, as currently reported	\$ 2,609.0	\$ 1,964.4		

⁽¹⁾ Prior to the TEPPCO Merger, we and TEPPCO were joint venture partners in Jonah. As a result of the TEPPCO Merger, Jonah became a consolidated subsidiary.

NOTE 15. RELATED PARTY TRANSACTIONS

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

	FOR YEAR ENDED DECEMBER 31,					
	2009		2008			2007
Revenues – related parties:						
EPCO and affiliates	\$	_	\$	_	\$	0.2
Energy Transfer Equity and subsidiaries		423.1		618.5		294.5
Unconsolidated affiliates		175.9		396.9		290.5
Total revenue – related parties	\$	599.0	\$	1,015.4	\$	585.2
Costs and expenses – related parties:						
EPCO and affiliates	\$	590.3	\$	554.2	\$	470.3
Energy Transfer Equity and subsidiaries		443.8		192.2		35.2
Cenac and affiliates		40.9		48.3		_
Unconsolidated affiliates		38.2		56.1		41.0
Total costs and expenses – related parties	\$	1,113.2	\$	850.8	\$	546.5
Other expense – related parties:						
EPCO and affiliates	\$	4.1	\$	0.3	\$	0.2

⁽²⁾ Represents the eliminations of revenues between Enterprise Products Partners, TEPPCO and Jonah.

⁽³⁾ Represents equity earnings from Jonah recorded by Enterprise Products Partners and TEPPCO prior to the merger.

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

	DECEMBER 31,				
	2	2009	2008		
Accounts receivable - related parties:					
EPCO and affiliates	\$	_	\$ 0.2		
Energy Transfer Equity and subsidiaries		28.2	35.0		
Other		10.2	0.1		
Total accounts receivable – related parties	\$	38.4	\$ 35.3		
Accounts payable - related parties:					
EPCO and affiliates	\$	26.8	\$ 14.1		
Energy Transfer Equity and subsidiaries		33.4	0.1		
Other		9.6	3.2		
Total accounts payable – related parties	\$	69.8	\$ 17.4		

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

Relationship with EPCO and Affiliates

We have an extensive and ongoing relationship with EPCO and its affiliates, which include the following significant entities that are not a part of our consolidated group of companies:

- EPCO and its privately held affiliates;
- EPGP, our sole general partner;
- Enterprise GP Holdings, which owns and controls our general partner; and
- the Employee Partnerships (see Note 5).

EPCO is a privately held company controlled by Dan L. Duncan, who is also a Director and Chairman of EPGP, our general partner. At December 31, 2009, EPCO and its affiliates beneficially owned interests in the following entities:

		PERCENTAGE OF
	NUMBER OF UNITS	OUTSTANDING UNITS
Enterprise Products Partners (1) (2)	191,363,613	31.3%
Enterprise GP Holdings (3)	108,503,133	78.0%

- (1) Includes 4,520,431 Class B units and 21,167,783 common units owned by Enterprise GP Holdings.
- (2) Enterprise GP Holdings owns 100% of our general partner, EPGP.
- (3) An affiliate of EPCO also owns 100% of the general partner of Enterprise GP Holdings, EPE Holdings.

The principal business activity of EPGP is to act as our managing partner. The executive officers and certain of the directors of EPGP and EPE Holdings are employees of EPCO. The following table presents cash distributions received by EPGP for the periods indicated:

	FOR YEAR ENDED DECEMBER 31,						
	2009	2008	2007				
General partner distributions	\$ 21.8	\$ 18.2	\$ 17.0				
Incentive distributions	161.3	125.9	107.4				
Total distributions	\$ 183.1	\$ 144.1	\$ 124.4				

We and EPGP are both separate legal entities apart from each other and apart from EPCO, Enterprise GP Holdings and their respective other affiliates, with assets and liabilities that are separate from those of EPCO, Enterprise GP Holdings and their respective other affiliates. EPCO and its privately held subsidiaries depend on the cash distributions they receive from us, Enterprise GP Holdings and other investments to fund their other operations and to meet their debt obligations. The following table presents cash distributions received by EPCO and its privately held affiliates from us and Enterprise GP Holdings for the periods indicated:

	FOR YEAR ENDED DECEMBER 31,						
	2009	2008	2007				
Enterprise Products Partners	\$ 314.5	\$ 281.1	\$ 263.4				
Enterprise GP Holdings	205.2	158.7	125.5				
Total distributions	\$ 519.7	\$ 439.8	\$ 388.9				

Substantially all of the ownership interests in us that are owned or controlled by Enterprise GP Holdings are pledged as security under its credit facility. In addition, substantially all of the ownership interests in us that are owned or controlled by EPCO and its affiliates, other than those interests owned by Enterprise GP Holdings, Dan Duncan LLC and certain trusts affiliated with Dan L. Duncan, are pledged as security under the credit facility of a privately held affiliate of EPCO. This credit facility contains customary and other events of default relating to EPCO and certain affiliates, including Enterprise GP Holdings and us.

We have entered into an agreement with an affiliate of EPCO to provide trucking services to us for the transportation of NGLs and other products. We also lease office space in various buildings from affiliates of EPCO. The rental rates in these lease agreements approximate market rates.

EPCO Administrative Services Agreement

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

- EPCO will provide selling, general and administrative services, and management and operating services, as may be necessary to manage and operate our businesses, properties and assets (all in accordance with prudent industry practices). EPCO will employ or otherwise retain the services of such personnel as may be necessary to provide such services.
- We are required to reimburse EPCO for its services in an amount equal to the sum of all costs and expenses incurred by EPCO which are directly or indirectly related to our business or activities (including expenses reasonably allocated to us by EPCO). In addition, we have agreed to pay all sales, use, excise, value added or similar taxes, if any, that may be applicable from time to time in respect of the services provided to us by EPCO.
- EPCO will allow us to participate as a named insured in its overall insurance program, with the associated premiums and other costs being allocated to us.

Under the ASA, EPCO subleases to us (for \$1 per year) certain equipment which it holds pursuant to operating leases and has assigned to us its purchase option under such leases (the "retained leases"). EPCO remains liable for the actual cash lease payments associated with these agreements. We record the full value of these payments made by EPCO on our behalf as a non-cash related party operating lease expense, with the offset to equity accounted for as a general contribution to our partnership.

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

	FOR YEAR ENDED DECEMBER 31,										
	2009	2008	2007								
Operating costs and expenses	\$ 495.3	\$ 463.2	\$ 387.7								
General and administrative expenses	95.0	91.0	82.6								
Total costs and expenses	\$ 590.3	\$ 554.2	\$ 470.3								

Since the vast majority of such expenses are charged to us 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 with respect to business opportunities (as defined within the ASA) with third parties. The EPCO Group includes EPCO and its other affiliates, but excludes Enterprise Products Partners, Enterprise GP Holdings, Duncan Energy Partners and their respective general partners.

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

Relationship with Energy Transfer Equity

Enterprise GP Holdings acquired equity method investments in Energy Transfer Equity and its general partner in May 2007. As a result, Energy Transfer Equity and its consolidated subsidiaries became related parties to our consolidated businesses.

We have a long-term revenue generating contract with Titan Energy Partners, L.P. ("Titan"), a consolidated subsidiary of ETP. Titan purchases substantially all of its propane requirements from us. The contract continues until March 31, 2010 and contains renewal and extension options. We and Energy Transfer Company ("ETC OLP") transport natural gas on each other's systems and share operating expenses on certain pipelines. ETC OLP also sells natural gas to us.

Relationships with Unconsolidated Affiliates

Many of our unconsolidated affiliates perform supporting or complementary roles to our other business operations. Since we and our affiliates hold ownership interests in these entities and directly or indirectly benefit from our related party transactions with such entities, they are presented here. The following information summarizes significant related party transactions with our current unconsolidated affiliates:

- We sell natural gas to Evangeline, which, in turn, uses the natural gas to satisfy supply commitments it has
 with a major Louisiana utility. Revenues from Evangeline were \$155.5 million, \$362.9 million and \$268.0
 million for the years ended December 31, 2009, 2008 and 2007, respectively.
- We pay Promix for the transportation, storage and fractionation of NGLs. In addition, we sell natural gas to Promix for its plant fuel requirements. Revenues from Promix were \$11.0 million, \$24.5 million and \$17.3 million for the years ended December 31, 2009, 2008 and 2007, respectively. Expenses with Promix were \$26.0 million, \$38.7 million and \$30.4 million for the years ended December 31, 2009, 2008 and 2007, respectively.

- For the years ended December 31, 2008 and 2007, we paid \$1.7 million and \$3.8 million, respectively, to Centennial in connection with a pipeline capacity lease. In addition, we paid \$6.7 million, \$6.6 million and \$5.3 million to Centennial for the years ended December 31, 2009, 2008 and 2007 for other pipeline transportation services, respectively.
- For the years ended December 31, 2009, 2008 and 2007, we paid Seaway \$3.4 million, \$6.0 million and \$4.7 million, respectively, for transportation and tank rentals in connection with our crude oil marketing activities.
- We perform management services for certain of our unconsolidated affiliates. We charged such affiliates \$10.7 million, \$11.2 million and \$11.0 million for the years ended December 31, 2009, 2008 and 2007, respectively.

Relationship with Duncan Energy Partners

Duncan Energy Partners was formed in September 2006 and did not acquire any assets prior to February 5, 2007, which was the date it completed its initial public offering and acquired controlling interests in five midstream energy businesses from EPO in a drop down transaction. On December 8, 2008, through a second drop down transaction, Duncan Energy Partners acquired controlling interests in three additional midstream energy businesses from EPO. The business purpose of Duncan Energy Partners is to acquire, own and operate a diversified portfolio of midstream energy assets and to support the growth objectives of EPO and other affiliates under common control. Duncan Energy Partners is engaged in: (i) the gathering, transportation and storage of natural gas; (ii) NGL transportation and fractionation; (iii) the storage of NGL and petrochemical products; (iv) the transportation of petrochemical products; and (v) the marketing of NGLs and natural gas.

At December 31, 2009, Duncan Energy Partners is owned 99.3% by its limited partners and 0.7% by its general partner, DEP GP, which is a wholly owned subsidiary of EPO. DEP GP is responsible for managing the business and operations of Duncan Energy Partners. DEP Operating Partnership L.P., a wholly owned subsidiary of Duncan Energy Partners, conducts substantially all of Duncan Energy Partners' business. At December 31, 2009, EPO owned 58.6% of Duncan Energy Partners' limited partner interests and 100% of its general partner. Due to our control of Duncan Energy Partners, its financial statements are consolidated with those of our own and our transactions with Duncan Energy Partners are eliminated in consolidation.

Relationship with Cenac

In connection with our marine services acquisition in February 2008, Cenac and affiliates became a related party of ours. We entered into a transitional operating agreement with Cenac in which our fleet of tow boats and tank barges (which were primarily acquired from Cenac) continued to be operated by employees of Cenac for a period of up to two years following the acquisition. Under this agreement, we paid Cenac a monthly operating fee and reimbursed Cenac for personnel salaries and related employee benefit expenses, certain repairs and maintenance expenses and insurance premiums on the equipment. Effective August 1, 2009, the transitional operating agreement was terminated. Personnel providing services pursuant to the agreement became employees of EPCO and will continue to provide services under the ASA. Concurrently with the termination of the transitional operating agreement, we entered into a two-year consulting agreement with Mr. Cenac and Cenac Marine Services, L.L.C. under which Mr. Cenac has agreed to supervise the day-to-day operations of our marine services business and, at our request, provide related management and transitional services.

NOTE 16. PROVISION FOR INCOME TAXES

Our provision for income taxes relates primarily to federal and state income taxes of Seminole and Dixie, our two largest corporations subject to such income taxes. In addition, with the amendment of the Texas Margin Tax, we have become a taxable entity in the state of Texas. Our federal and state income tax provision is summarized below:

	FOR YEAR ENDED DECEMBER 31,												
	2009	2008	2007										
Current:													
Federal	\$ 7.9	\$ 4.9	\$ 4.7										
State	11.9	23.9	5.1										
Foreign	1.0	0.4	0.1										
Total current	20.8	29.2	9.9										
Deferred:													
Federal	4.8	0.8	2.7										
State	(0.3)	1.0	3.1										
Total deferred	4.5	1.8	5.8										
Total provision for income taxes	\$ 25.3	\$ 31.0	\$ 15.7										

A reconciliation of the provision for income taxes with amounts determined by applying the statutory U.S. federal income tax rate to income before income taxes is as follows:

	FOR YEAR ENDED DECEMBER 31,											
		2009		2008		2007						
Pre Tax Net Book Income ("NBI")	\$	1,180.4	\$	1,219.9	\$	853.7						
Texas Margin Tax	\$	10.1	\$	23.9	\$	7.7						
State income taxes (net of federal benefit)		1.3		0.5		0.3						
Federal income taxes computed by applying the federal												
statutory rate to NBI of corporate entities		8.3		6.3		5.3						
Valuation allowance		(1.7)		(1.4)		2.3						
Expiration of tax net operating loss		1.7		_		_						
Other permanent differences		5.6		1.7		0.1						
Provision for income taxes	\$	25.3	\$	31.0	\$	15.7						
Effective income tax rate		2.1%		2.5%		1.8%						

Significant components of deferred tax assets and deferred tax liabilities as of December 31, 2009 and 2008 are as follows:

	AT DECEMBER 31,							
	2009	2008						
Deferred tax assets:								
Net operating loss carryovers (1)	\$ 24.6	\$ 26.3						
Property, plant and equipment	_	0.8						
Employee benefit plans	2.8	2.6						
Deferred revenue	1.1	1.0						
Reserve for legal fees and damages	_	0.3						
Equity investment in partnerships	1.0	0.6						
AROs	0.1	0.1						
Accruals	1.3	0.9						
Total deferred tax assets	30.9	32.6						
Valuation allowance (2)	2.2	3.9						
Net deferred tax assets	28.7	28.7						
Deferred tax liabilities:								
Property, plant and equipment	97.4	92.9						
Other		0.1						
Total deferred tax liabilities	97.4	93.0						
Total net deferred tax liabilities	\$ (68.7)	\$ (64.3)						
Current portion of total net deferred tax assets	\$ 1.9	\$ 1.4						
Long-term portion of total net deferred tax liabilities	\$ (70.6)	\$ (65.7)						

- (1) These losses expire in various years between 2010 and 2028 and are subject to limitations on their utilization
- (2) We record a valuation allowance to reduce our deferred tax assets to the amount of future benefit that is more likely than not to be realized.

On May 18, 2006, the State of Texas enacted House Bill 3 which revised the pre-existing state franchise tax. In general, legal entities that conduct business in Texas are subject to the Revised Texas Franchise Tax (i.e., the Texas Margin Tax), including previously non-taxable entities such as limited liability companies, limited partnerships and limited liability partnerships. The tax is assessed on Texas sourced taxable margin which is defined as the lesser of (i) 70% of total revenue or (ii) total revenue less (a) cost of goods sold or (b) compensation and benefits.

Although the bill states that the Texas Margin Tax is not an income tax, it has the characteristics of an income tax since it is determined by applying a tax rate to a base that considers both revenues and expenses. Due to the enactment of the Texas Margin Tax, we recorded a net deferred tax asset of \$0.3 million and a liability of \$1.0 million during the years ended December 31, 2009 and 2008, respectively. The offsetting net benefit of \$0.3 million and net charge of \$1.0 million is shown on our Statements of Consolidated Operations for the years ended December 31, 2009 and 2008, respectively, as a component of "Provision for income taxes."

NOTE 17. EARNINGS PER UNIT

Basic earnings per unit is computed by dividing net income or loss available to limited partner interests by the weighted-average number of distribution-bearing units outstanding during a period. Diluted earnings per unit is computed by dividing net income or loss available to limited partner interests by the sum of: (i) the weighted-average number of distribution-bearing units outstanding during a period (as used in determining basic earnings per unit); (ii) the weighted-average number of phantom units outstanding during a period; (iii) the weighted-average number of Class B units outstanding during a period; and (iv) the number of incremental common units resulting from the assumed exercise of dilutive unit options outstanding during a period (the "incremental option units").

In a period of net losses, restricted units, Class B units, phantom units and incremental option units are excluded from the calculation of diluted earnings per unit due to their antidilutive effect. The dilutive incremental option units are calculated using the treasury stock method, which assumes that proceeds from the exercise of all in-themoney options at the end of each period are used to repurchase common units at an average market value during the period. The amount of common units remaining after the proceeds are exhausted represents the potentially dilutive effect of the securities.

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

	FOR YEAR ENDED DECEMBER 31,										
	2009	2008	2007								
Net income attributable to Enterprise Products Partners L.P.	\$1,030.9	\$ 954.0	\$ 533.6								
Less incentive earnings allocations to EPGP	(161.3)	(125.9)	(107.4)								
Net income available after incentive earnings allocation	869.6	828.1	426.2								
Multiplied by EPGP ownership interest	2.0%	2.0%	2.0%								
Standard earnings allocation to EPGP	\$ 17.4	\$ 16.6	\$ 8.5								
Incentive earnings allocation to EPGP Standard earnings allocation to EPGP	\$ 161.3 17.4	\$ 125.9 16.6	\$ 107.4 8.5								
Net income available to EPGP	178.7	142.5	115.9								
Adjustment for master limited partnerships (1)	7.7	5.2	4.5								
Net income available to EPGP for EPU purposes	\$ 186.4	\$ 147.7	\$ 120.4								

⁽¹⁾ FASB guidance specific to master limited partnerships has been applied for purposes of computing basic and diluted earnings per unit.

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

	FOR YEAR ENDED DECEMBER 31,							
		2009		2008		2007		
BASIC EARNINGS PER UNIT								
Numerator								
Net income attributable to Enterprise Products Partners L.P.	\$	1,030.9	\$	954.0	\$	533.6		
Net income available to EPGP for EPU purposes		(186.4)		(147.7)		(120.4)		
Net income available to limited partners	\$_	844.5	\$	806.3	\$	413.2		
Denominator								
Common units		484.3		435.4		432.5		
Time-vested restricted units		2.5		2.0		1.5		
Total		486.8		437.4		434.0		
Basic earnings per unit								
Net income per unit before EPGP earnings allocation	\$	2.11	\$	2.18	\$	1.23		
Net income available to EPGP		(0.38)		(0.34)		(0.28)		
Net income available to limited partners	\$	1.73	\$	1.84	\$	0.95		
DILUTED EARNINGS PER UNIT								
Numerator								
Net income attributable to Enterprise Products Partners L.P.	\$	1,030.9	\$	954.0	\$	533.6		
Net income available to EPGP for EPU purposes		(186.4)		(147.7)		(120.4)		
Net income available to limited partners	\$	844.5	\$	806.3	\$	413.2		
Denominator								
Common units		484.3		435.4		432.5		
Time-vested restricted units		2.5		2.0		1.5		
Class B units		0.8		_		_		
Incremental option units		0.2		0.2		0.4		
Total		487.8		437.6		434.4		
Diluted earnings per unit								
Net income per unit before EPGP earnings allocation	\$	2.11	\$	2.18	\$	1.23		
Net income available to EPGP		(0.38)		(0.34)		(0.28)		
Net income available to limited partners	\$	1.73	\$	1.84	\$	0.95		

NOTE 18. COMMITMENTS AND CONTENGENCIES

Litigation

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

We evaluate our ongoing litigation based upon a combination of litigation and settlement alternatives. These reviews are updated as the facts and combinations of the cases develop or change. Assessing and predicting the outcome of these matters involves substantial uncertainties. In the event that the assumptions we used to evaluate these matters change in future periods or new information becomes available, we may be required to record a liability for an adverse outcome. In an effort to mitigate potential adverse consequences of litigation, we could also seek to settle legal proceedings brought against us. We have not recorded any significant reserves for any litigation in our financial statements.

On September 18, 2006, Peter Brinckerhoff, a purported unitholder of TEPPCO, filed a complaint in the Court of Chancery of the State of Delaware (the "Delaware Court"), in his individual capacity, as a putative class action on behalf of other unitholders of TEPPCO and derivatively on behalf of TEPPCO, concerning, among other things, certain transactions involving TEPPCO and us or our affiliates. Mr. Brinckerhoff filed an amended complaint on July 12, 2007. The amended complaint names as defendants: (i) TEPPCO, certain of its current and former directors, and certain of its affiliates; (ii) us and certain of our affiliates; (iii) EPCO; and (iv) Dan L. Duncan.

The amended complaint alleges, among other things, that the defendants caused TEPPCO to enter into specified transactions that were unfair to TEPPCO or otherwise unfairly favored us or our affiliates over TEPPCO. These transactions are alleged to include: (i) the joint venture to further expand the Jonah system entered into by TEPPCO and us in August 2006 (the plaintiff alleges that TEPPCO did not receive fair value for allowing us to participate in the joint venture); (ii) the sale by TEPPCO of its Pioneer natural gas processing plant and certain gas processing rights to us in March 2006 (the plaintiff alleges that the purchase price we paid did not provide fair value to TEPPCO); and (iii) certain amendments to TEPPCO's partnership agreement, including a reduction in the maximum tier of TEPPCO's incentive distribution rights in exchange for TEPPCO units. The amended complaint seeks: (i) rescission of the amendments to TEPPCO's partnership agreement; (ii) damages for profits and special benefits allegedly obtained by defendants as a result of the alleged wrongdoings in the amended complaint; and (iii) an award to plaintiff of the costs of the action, including fees and expenses of his attorneys and experts. By its Opinion and Order dated November 25, 2008, the Delaware Court dismissed Mr. Brinckerhoff's individual and putative class action claims with respect to the amendments to TEPPCO's partnership agreement. We refer to this action and the remaining claims in this action as the "Derivative Action."

On April 29, 2009, Peter Brinckerhoff and Renee Horowitz, as Attorney in Fact for Rae Kenrow, purported unitholders of TEPPCO, filed separate complaints in the Delaware Court as putative class actions on behalf of other unitholders of TEPPCO, concerning the TEPPCO Merger. On May 11, 2009, these actions were consolidated under the caption Texas Eastern Products Pipeline Company, LLC Merger Litigation, C.A. No. 4548-VCL ("Merger Action"). The complaints name as defendants us, EPGP, TEPPCO GP, the directors of TEPPCO GP, EPCO and Dan L. Duncan.

The Merger Action complaints allege, among other things, that the terms of the merger (as proposed as of the time the Merger Action complaints were filed) are grossly unfair to TEPPCO's unitholders and that the TEPPCO Merger is an attempt to extinguish the Derivative Action without consideration. The complaints further allege that the process through which the Special Committee of the ACG Committee of TEPPCO GP was appointed to consider the TEPPCO Merger is contrary to the spirit and intent of TEPPCO's partnership agreement and constitutes a breach of the implied covenant of fair dealing.

The complaints seek relief: (i) enjoining the defendants and all persons acting in concert with them from pursuing the TEPPCO Merger; (ii) rescinding the TEPPCO Merger to the extent it is consummated, or awarding rescissory damages in respect thereof; (iii) directing the defendants to account for all damages suffered or to be suffered by the plaintiffs and the purported class as a result of the defendants' alleged wrongful conduct; and (iv) awarding plaintiffs' costs of the actions, including fees and expenses of their attorneys and experts.

On August 5, 2009, the parties entered into a Stipulation and Agreement of Compromise, Settlement and Release (the "Settlement Agreement"). Pursuant to the Settlement Agreement, the board of directors of TEPPCO GP recommended to TEPPCO's unitholders that they approve the adoption of the merger agreement and took all necessary steps to seek unitholder approval for the merger.

The Delaware Court approved the Settlement Agreement on January 15, 2010, dismissing with prejudice the Merger Action and the Derivative Action.

Additionally, on June 29 and 30, 2009, respectively, M. Lee Arnold and Sharon Olesky, purported unitholders of TEPPCO, filed separate complaints in the District Courts of Harris County, Texas, as putative class actions on behalf of other unitholders of TEPPCO, concerning the TEPPCO Merger (the "Texas Actions"). The complaints name as defendants us, TEPPCO, TEPPCO GP, EPGP, EPCO, Dan L. Duncan, Jerry Thompson and the board of directors of TEPPCO GP. The allegations in the complaints are similar to the complaints filed in Delaware on April 29, 2009 and seek similar relief. The named plaintiffs in the two Texas Actions (the "Texas Plaintiffs/Objectors") also appeared in the Delaware proceedings as objectors to the settlement of those cases which were then awaiting court approval. On October 7, 2009, the Texas Plaintiffs/Objectors and the parties to the Settlement Agreement entered into a Stipulation to Withdraw Objection (the "Stipulation"). In accordance with the Stipulation, and upon the receipt of Final Court Approval (as defined in the Settlement Agreement), the Texas Plaintiffs/Objectors agreed to dismiss the Texas Actions with prejudice. As of March 1, 2010, the Texas Actions have been dismissed with prejudice pursuant to the Settlement Agreement.

In February 2007, EPO received a letter from the Environment and Natural Resources Division of the U.S. Department of Justice related to an ammonia release in Kingman County, Kansas on October 27, 2004 from a pressurized anhydrous ammonia pipeline owned by a third-party, Magellan Ammonia Pipeline, L.P. ("Magellan"), and a previous release of ammonia on September 27, 2004 from the same pipeline. EPO was the operator of this pipeline until July 1, 2008. This matter was settled in September 2009, and Magellan has agreed to pay all assessed penalties.

The Attorney General of Colorado on behalf of the Colorado Department of Public Health and Environment ("CDPHE") filed suit against us and others on April 15, 2008 in connection with the construction of a pipeline near Parachute, Colorado. The State sought a temporary restraining order and an injunction to halt construction activities since it alleged that the defendants failed to install measures to minimize damage to the environment and to follow requirements for the pipeline's storm water permit and appropriate storm water plan. We have entered into a settlement agreement with the State that dismisses the suit and assesses a fine of approximately \$0.2 million.

The CDPHE, through its Air Pollution Control Division, has proposed a Compliance Order on Consent with Enterprise Gas Processing, L.L.C for alleged violations of the Colorado Air Pollution and Prevention and Control Act ("Colorado Act") with respect to operations of the Meeker Gas Processing Plant. The Compliance Order proposes an administrative fine of approximately \$0.3 million and would require the Meeker Gas Processing Plant to be operated in compliance with the Colorado Act. We have entered into discussions regarding the terms of the Compliance Order.

In January 2009, the State of New Mexico filed suit in District Court in Santa Fe County, New Mexico, under the New Mexico Air Quality Control Act. The lawsuit arose out of a February 27, 2008 Notice Of Violation issued to Marathon Oil Corp. ("Marathon") as operator of the Indian Basin natural gas processing facility located in Eddy County, New Mexico. We own a 42.4% undivided interest in the assets comprising the Indian Basin facility. The State alleges violations of its air laws. Marathon agreed to a Consent Decree with the State which was approved by the District Court on December 21, 2009. Under the Decree, Marathon paid the State approximately \$0.6 million, agreed to \$4.5 million of additional environmental projects in New Mexico and agreed to two projects for "corrective measures" at the facility. We are in discussions with Marathon regarding the responsibility for these payments. We believe that any potential payment we make will not have a material impact on our consolidated financial position, results of operations or cash flows.

In connection with our dissociation from TOPS (see Note 8), Oiltanking filed an original petition against Enterprise Offshore Port System, LLC, EPO, TEPPCO O/S Port System, LLC, TEPPCO and TEPPCO GP in the District Court of Harris County, Texas, 61st Judicial District (Cause No. 2009-31367), asserting, among other things, that the dissociation was wrongful and in breach of the TOPS partnership agreement, citing provisions of the agreement that, if applicable, would continue to obligate us and TEPPCO to make capital contributions to fund the project and impose liabilities on us and TEPPCO. On September 17, 2009, we and TEPPCO entered into a settlement agreement with certain affiliates of Oiltanking and TOPS that resolved all disputes between the parties related to the business and affairs of the TOPS project (including the litigation described above). We recognized approximately \$66.9 million of expense during 2009 in connection with this settlement. This charge is classified within our Offshore Pipelines & Services business segment.

Regulatory Matters

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

Contractual Obligations

The following table summarizes our various contractual obligations at December 31, 2009. A description of each type of contractual obligation follows:

	PAYMENT OR SETTLEMENT DUE BY PERIOD													
CONTRACTUAL OBLIGATIONS		TOTAL		2010		2011		2012		2013		2014	TH	IEREAFTER
Scheduled maturities of long-term debt	\$	11,297.0	\$	554.0	\$	907.3	\$	1,195.5	\$	1,200.0	\$	1,150.0	\$	6,290.2
Estimated cash interest payments	\$	12,372.2	\$	667.4	\$	618.3	\$	571.9	\$	502.9	\$	436.5	\$	9,575.2
Operating lease obligations	\$	343.9	\$	37.6	\$	35.3	\$	32.7	\$	27.3	\$	21.5	\$	189.5
Purchase obligations:														
Product purchase commitments:														
Estimated payment obligations:														
Natural gas	\$	5,697.6	\$	1,308.9	\$	685.5	\$	696.3	\$	487.5	\$	471.8	\$	2,047.6
NGLs	\$	2,943.0	\$	997.0	\$	339.3	\$	329.8	\$	329.7	\$	329.7	\$	617.5
Crude oil	\$	237.3	\$	237.3	\$	_	\$	_	\$	_	\$	_	\$	_
Petrochemicals & refined products	\$	2,642.2	\$	1,486.6	\$	586.0	\$	238.5	\$	113.9	\$	72.4	\$	144.8
Other	\$	114.1	\$	21.2	\$	12.2	\$	11.9	\$	11.8	\$	11.0	\$	46.0
Underlying major volume commitments:														
Natural gas (in BBtus)		969,180		221,530		114,304		116,146		83,854		81,154		352,192
NGLs (in MBbls)		49,300		19,048		5,337		5,159		5,158		5,158		9,440
Crude oil (in MBbls)		2,985		2,985		_		_		_		_		_
Petrochemicals & refined products (in MBbls)		35,034		19,523		7,856		3,266		1,509		960		1,920
Service payment commitments	\$	575.6	\$	72.0	\$	57.0	\$	56.7	\$	55.1	\$	55.0	\$	279.8
Capital expenditure commitments	\$	497.5	\$	497.5	\$	_	\$	_	\$	_	\$	_	\$	_

<u>Scheduled Maturities of Long-Term Debt</u>. We have long-term and short-term payment obligations under debt agreements. Amounts shown in the preceding table represent our scheduled future maturities of debt principal for the periods indicated. See Note 12 for additional information regarding our consolidated debt obligations.

<u>Operating Lease Obligations</u>. 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; (ii) leased office space with affiliates of EPCO; and (iii) land held pursuant to right-of-way agreements. In general, our material lease agreements have current terms that range from 14 to 20 years. The agreements for leased office space with affiliates of EPCO and underground NGL storage caverns we lease from a third party include renewal options that could extend these contracts for up to an additional 20 years. The remainder of our material lease agreements do not provide for additional renewal terms.

Lease expense is charged to operating costs and expenses on a straight line basis over the period of expected economic benefit. Contingent rental payments are expensed as incurred. We are generally required to perform routine maintenance on the underlying leased assets. In addition, certain leases give us the option to make leasehold improvements. Maintenance and repairs of leased assets resulting from our operations are charged to expense as incurred. We did not make any significant leasehold improvements during the years ended December 31, 2009, 2008 or 2007.

The operating lease commitments shown in the preceding table exclude the non-cash, related party expense associated with retained leases contributed to us by EPCO in 1998. EPCO remains liable for the actual cash lease payments associated with these agreements, which it accounts for as operating leases. At December 31, 2009, the retained leases were for approximately 100 railcars. EPCO's minimum future rental payments under these leases are \$0.7 million for each of the years 2010 through 2015 and \$0.3 million for 2016. We record the full value of these payments made by EPCO on our behalf as a non-cash related party operating lease expense, with the offset to equity accounted for as a general contribution to our partnership.

The retained lease agreements contain lessee purchase options, which are at prices that approximate fair value of the underlying leased assets. EPCO has assigned these purchase options to us. We exercised our election under the retained leases to purchase a cogeneration unit in December 2008 for \$2.3 million. Should we decide to exercise the purchase option associated with the remaining agreement, we would pay the original lessor \$3.1 million in June 2016.

Lease and rental expense included in costs and expenses was \$60.7 million, \$56.8 million and \$61.4 million during the years ended December 31, 2009, 2008 and 2007, respectively.

<u>Purchase Obligations</u>. We define a purchase obligation as an agreement to purchase goods or services that is enforceable and legally binding (unconditional) on us that specifies all significant terms, including: fixed or minimum quantities to be purchased; fixed, minimum or variable price provisions; and the approximate timing of the transactions. We have classified our unconditional purchase obligations into the following categories:

• We have long and short-term product purchase obligations for natural gas, NGLs, crude oil, refined products and certain petrochemicals with third-party suppliers. The prices that we are obligated to pay under these contracts approximate market prices at the time we take delivery of the volumes. The preceding table shows our volume commitments and estimated payment obligations under these contracts for the periods indicated. Our estimated future payment obligations are based on the contractual price under each contract for purchases made at December 31, 2009 applied to all future volume commitments. Actual future payment obligations may vary depending on prices at the time of delivery. At December 31, 2009, we do not have any significant product purchase commitments with fixed or minimum pricing provisions with remaining terms in excess of one year.

- We have long and short-term commitments to pay third-party providers for services. Our contractual service payment commitments primarily represent our obligations under firm pipeline transportation contracts on pipelines owned by third parties. Payment obligations vary by contract, but generally represent a price per unit of volume multiplied by a firm transportation volume commitment. The preceding table shows our estimated future payment obligations under these service contracts.
- We have short-term payment obligations relating to our capital projects and those of our unconsolidated
 affiliates. These commitments represent unconditional payment obligations to vendors for services rendered
 or products purchased. The preceding table presents our share of such commitments for the periods
 indicated.

Commitments Under Equity Compensation Plans of EPCO

In accordance with our agreements with EPCO, we reimburse EPCO for our share of its compensation expense associated with certain employees who perform management, administrative and operating functions for us (see Note 15). See Note 5 for additional information regarding our accounting for equity awards.

Other Claims

As part of our normal business activities with joint venture partners, customers and suppliers, we occasionally have claims made against us as a result of disputes related to contractual agreements. As of December 31, 2009, claims against us totaled approximately \$21.1 million. These matters are in various stages of assessment and the ultimate outcome of such disputes cannot be reasonably estimated. However, in our opinion, the likelihood of a material adverse outcome related to disputes against us is remote. Accordingly, accruals for loss contingencies related to these matters that might result from the resolution of such disputes have not been reflected in our consolidated financial statements.

Other Commitments

We transport and store natural gas, NGLs and petrochemicals for third parties under various processing, storage, transportation and similar agreements. These volumes are either accrued as product payables, in transit for delivery to our customers or held at our storage facilities for redelivery to our customers. Under terms of our storage agreements, we are generally required to redeliver volumes to the owner on demand. At December 31, 2009, NGL and petrochemical products aggregating 29.8 million barrels were due to be redelivered to their owners along with 17,112 BBtus of natural gas. See Note 2 for more information regarding accrued product payables.

Centennial Guarantees

We have certain guarantee obligations in connection with our ownership interest in Centennial. We have guaranteed one-half of Centennial's debt obligations, which obligates us to an estimated payment of \$60.0 million in the event of a default by Centennial. At December 31, 2009, we had a liability of \$8.4 million representing the estimated fair value of our share of the Centennial debt guaranty. See Note 12 for information regarding Centennial's debt obligations.

In lieu of Centennial procuring insurance to satisfy third-party liabilities arising from a catastrophic event, we and Centennial's other joint venture partner have entered a limited cash call agreement. We are obligated to contribute up to a maximum of \$50.0 million (in proportion to our ownership interest in Centennial) in the event of a catastrophic event. At December 31, 2009, we had a liability of \$3.6 million representing the estimated fair value of our cash call guaranty. Cash contributions to Centennial under the limited cash call agreement may be covered by our insurance depending on the nature of the catastrophic event.

NOTE 19. SIGNIFICANT RISKS AND UNCERTAINTIES

Nature of Operations in Midstream Energy Industry

Our operations are within the midstream energy industry, which includes gathering, transporting, processing, fractionating and storing natural gas, NGLs, crude oil, refined products and certain petrochemicals. We also market natural gas, NGLs, crude oil and other hydrocarbon products. As such, our financial position, results of operations and cash flows may be affected by changes in the commodity prices of these hydrocarbon products, including changes in the relative price levels among these products (e.g., natural gas processing margins are influenced by the ratio of natural gas prices to crude oil prices). The prices of hydrocarbon products are subject to fluctuation 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 gathered, transported, processed, fractionated or stored 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, NGLs, refined products and crude oil handled by our facilities.

A reduction in demand for natural gas, crude oil, NGL and other hydrocarbon 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 such products; (iii) increased competition from other 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 financial position, results of operations and cash flows.

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. See Note 14 for information regarding our largest customer.

Counterparty Risk with Respect to Derivative Instruments

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

Insurance-Related Risks

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

EPCO's deductible for onshore physical damage from windstorms is currently \$25.0 million per storm. EPCO's onshore program currently provides \$150.0 million per occurrence for named windstorm events. With respect to offshore assets, the windstorm deductible is \$75.0 million per storm. EPCO's offshore program currently provides \$100.0 million in the aggregate. For non-windstorm events, EPCO's deductible for both onshore and offshore physical damage is \$5.0 million per occurrence. For certain of our major offshore assets, our producer customers have agreed to provide a specified level of physical damage insurance for named windstorms. For example, the producers associated with our Independence Hub and Marco Polo platforms have agreed to cover windstorm generated physical damage costs up to \$250.0 million for each platform.

Business interruption coverage in connection with a windstorm event remains in place for onshore assets, but was eliminated for offshore assets. Onshore assets covered by business interruption insurance must be out-of-service in excess of 60 days before any losses from business interruption will be covered. Furthermore, pursuant to the current policy, we will now absorb 50% of the first \$50.0 million of any loss in excess of deductible amounts for our onshore assets.

The following table summarizes proceeds we received from weather-related business interruption and property damage insurance claims during the periods indicated:

	FOR YEAR ENDED DECEMBER 31,												
		2009		2008		2007							
Business interruption proceeds:													
Hurricanes Katrina and Rita in 2005	\$	_	\$	1.1	\$	33.9							
Hurricanes Gustav and Ike in 2008		33.2		_		_							
Other		_		_		1.4							
Total proceeds		33.2		1.1		35.3							
Property damage proceeds:													
Hurricanes Katrina and Rita in 2005		38.6		12.1		103.7							
Hurricanes Gustav and Ike in 2008		15.1		_		_							
Other		0.7		_		1.5							
Total proceeds		54.4		12.1		105.2							
Total	\$	87.6	\$	13.2	\$	140.5							

At December 31, 2009, we have \$37.6 million of estimated property damage claims outstanding related to these storms that we believe are probable of collection through 2010. To the extent we estimate the dollar value of such damages, please be aware that a change in our estimates may occur as additional information becomes available.

NOTE 20. SUPPLEMENTAL CASH FLOW INFORMATION

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

	FOR YEAR ENDED DECEMBER 31,										
	2009	2008	2007								
Decrease (increase) in:											
Accounts and notes receivable – trade	\$(1,069.1)	\$ 1,333.9	\$(1,175.8)								
Accounts receivable – related party	7.2	3.6	(37.0)								
Inventories	(317.4)	14.9	(20.4)								
Prepaid and other current assets	71.2	(26.9)	36.6								
Other assets	15.0	(11.7)	(6.7)								
Increase (decrease) in:											
Accounts payable – trade	(51.7)	(9.1)	193.8								
Accounts payable – related party	44.3	1.2	(2.2)								
Accrued product payables	1,552.9	(1,722.0)	2,195.2								
Accrued expenses	42.4	3.4	(809.3)								
Accrued interest	33.7	21.8	39.9								
Other current liabilities	(105.5)	(27.7)	44.5								
Other liabilities	22.9	7.5	(23.7)								
Net effect of changes in operating accounts	\$ 245.9	\$ (411.1)	\$ 434.9								
Cash payments for interest, net of \$53.1, \$90.7 and											
\$86.5 capitalized in 2009, 2008 and 2007, respectively	\$ 651.5	\$ 569.7	\$ 429.5								
Only and the following of the following states in the	Φ 00 5	Φ 6.0	Φ 50								
Cash payments for federal and state income taxes	\$ 29.5	\$ 6.8	\$ 5.8								

FOR VEAR ENDER RECEMBER OF

We incurred liabilities for construction in progress that had not been paid at December 31, 2009, 2008 and 2007 of \$182.6 million, \$107.9 million and \$107.0 million, respectively. Such amounts are not included under the caption "Capital expenditures" on the Statements of Consolidated Cash Flows.

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

NOTE 21. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

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

	FIRST Quarter	SECOND Quarter		THIRD Uarter	FOURTH QUARTER
For the Year Ended December 31, 2009:					
Revenues	\$ 4,886.9	\$ 5,434.3	\$	6,789.4	\$ 8,400.3
Operating income	482.8	373.3		356.3	611.6
Net income	315.5	212.5		187.8	439.3
Net income attributable to Enterprise Products Partners L.P.	225.3	186.6		212.9	406.1
Earnings per unit:					
Basic	\$ 0.41	\$ 0.32	\$	0.36	\$ 0.60
Diluted	\$ 0.41	\$ 0.32	\$	0.36	\$ 0.60
For the Year Ended December 31, 2008:					
Revenues	\$ 8,506.4	\$ 10,538.6	\$1	0,499.1	\$ 5,925.5
Operating income	469.7	454.6		401.0	423.1
Net income	336.0	320.0		258.1	274.8
Net income attributable to Enterprise Products Partners L.P.	259.6	263.3		203.1	228.0
Earnings per unit:					
Basic	\$ 0.51	\$ 0.52	\$	0.38	\$ 0.43
Diluted	\$ 0.51	\$ 0.52	\$	0.38	\$ 0.43

NOTE 22. CONDENSED CONSOLIDATING FINANCIAL INFORMATION

EPO conducts substantially all of our business. Currently, we have no independent operations and no material assets outside those of EPO. EPO consolidates the financial statements of Duncan Energy Partners with those of its own.

EPO has issued publicly traded debt securities. Enterprise Products Partners L.P., as the parent company of EPO, guarantees the debt obligations of EPO, with the exception of Duncan Energy Partners' debt obligations. If EPO were to default on any of its guaranteed debt, Enterprise Products Partners L.P. would be responsible for full repayment of that obligation. EPO's consolidated subsidiaries have no significant restrictions on their ability to pay distributions or make loans to Enterprise Products Partners L.P. See Note 12 for additional information regarding our consolidated debt obligations.

Immediately after the closing of the TEPPCO Merger, Enterprise Products Partners L.P. contributed its ownership interests in TEPPCO and TEPPCO GP to EPO. The following condensed consolidating financial information for EPO has been recast to include TEPPCO and TEPPCO GP using the same basis of presentation described in Note 1 for our consolidated financial statements.

In preparing our 2009 consolidated financial statements, management reevaluated the disclosure requirements of S-X Rule 3-10, *Financial Statements of Guarantors and Issuers of Guaranteed Securities Registered or Being Registered*, and determined that the following Condensed Consolidating Financial Information, rather than the previously disclosed consolidated financial information of EPO, should be prospectively included herein.

$\begin{array}{c} \textbf{CONDENSED} \ \ \textbf{CONSOLIDATING} \ \ \textbf{BALANCE} \ \ \textbf{SHEET} \\ \textbf{December 31, 2009} \end{array}$

		EPO AND S	SUBSIDIARIES				
	SUBSIDIARY ISSUER (EPO)	OTHER SUBSIDIARIES (NON-GUARANTOR)	EPO AND SUBSIDIARIES ELIMINATIONS AND ADJUSTMENTS	CONSOLIDATED EPO AND Subsidiaries	PARENT COMPANY (GUARANTOR)	ELIMINATIONS AND ADJUSTMENTS	CONSOLIDATED TOTAL
ASSETS							
Current assets:							
Cash and cash equivalents	\$ 14.4	\$ 46.3	\$ (6.2)	\$ 54.5	\$ —	\$ 0.2	\$ 54.7
Restricted cash	63.1	0.5	_	63.6	_	_	63.6
Accounts and notes receivable, net	509.6	2,674.0	(45.7)	3,137.9	(0.3)	(0.2)	3,137.4
Inventories	595.4	120.3	(3.8)	711.9	_	_	711.9
Prepaid and other current assets	185.4	100.6	(6.7)	279.3			279.3
Total current assets	1,367.9	2,941.7	(62.4)	4,247.2	(0.3)	_	4,246.9
Property, plant and equipment, net	1,436.1	16,242.0	11.1	17,689.2	_	_	17,689.2
Investments in unconsolidated affiliates	18,981.2	5,912.7	(24,003.3)	890.6	9,512.4	(9,512.4)	890.6
Intangible assets, net	170.0	910.3	(15.5)	1,064.8	_	_	1,064.8
Goodwill	473.7	1,544.6	_	2,018.3	_	_	2,018.3
Other assets	287.2	131.1	(177.4)	240.9		0.9	241.8
Total assets	\$ 22,716.1	\$ 27,682.4	\$ (24,247.5)	\$ 26,151.0	\$ 9,512.1	\$ (9,511.5)	\$ 26,151.6
LIABILITIES AND EQUITY							
Current liabilities:							
Accounts payable	\$ 146.3	\$ 551.5	\$ (217.4)	\$ 480.4	\$ —	\$ —	\$ 480.4
Accrued product payables	1,842.6	1,557.3	(6.9)	3,393.0	_	_	3,393.0
Other current liabilities	403.7	274.2	(15.3)	662.6	_	_	662.6
Total current liabilities	2,392.6	2,383.0	(239.6)	4,536.0	_	_	4,536.0
Long-term debt	10,777.6	568.8	_	11,346.4	_	_	11,346.4
Commitments and contingencies							
Other long-term liabilities	17.9	209.0	_	226.9	_	_	226.9
Equity:							
Controlling interests	9,528.0	21,058.3	(21,084.5)	9,501.8	9,512.1	(9,501.8)	9,512.1
Noncontrolling interests		3,463.3	(2,923.4)	539.9	_	(9.7)	530.2
Total equity	9,528.0	24,521.6	(24,007.9)	10,041.7	9,512.1	(9,511.5)	10,042.3
Total liabilities and equity	\$ 22,716.1	\$ 27,682.4	\$ (24,247.5)	\$ 26,151.0	\$ 9,512.1	\$ (9,511.5)	\$ 26,151.6

CONDENSED CONSOLIDATING BALANCE SHEET December 31, 2008

	EPO AND SUBSIDIARIES											
		JBSIDIARY Suer (EPO)		OTHER UBSIDIARIES N-GUARANTOR)	ELIM	EPO AND SUBSIDIARIES CONSOLIDATED ELIMINATIONS AND EPO AND ADJUSTMENTS SUBSIDIARIES		ENT COMPANY Uarantor)	LIMINATIONS ADJUSTMENTS	CO	NSOLIDATED TOTAL	
ASSETS												
Current assets:												
Cash and cash equivalents	\$	1.0	\$	69.7	\$	(9.4)	\$	61.3	\$ 0.2	\$ 0.2	\$	61.7
Restricted cash		203.8		_		_		203.8	_	_		203.8
Accounts and notes receivable, net		1,230.9		930.1		(84.9)		2,076.1	(7.7)	(4.6)		2,063.8
Inventories		288.8		129.3		(13.1)		405.0	_	_		405.0
Prepaid and other current assets		107.4		254.4		6.6		368.4				368.4
Total current assets		1,831.9		1,383.5		(100.8)		3,114.6	(7.5)	(4.4)		3,102.7
Property, plant and equipment, net		1,249.7		15,457.7		25.4		16,732.8	_	_		16,732.8
Investments in unconsolidated affiliates	1	13,389.3		5,297.4	(17,774.8)		911.9	6,097.5	(6,097.5)		911.9
Intangible assets, net		182.4		1,016.7		(16.2)		1,182.9	_	_		1,182.9
Goodwill		473.7		342.6		1,203.3		2,019.6	_	_		2,019.6
Other assets		308.3		159.0		(206.2)		261.1	_	0.6		261.7
Total assets	\$ 1	17,435.3	\$	23,656.9	\$(16,869.3)	\$	24,222.9	\$ 6,090.0	\$ (6,101.3)	\$:	24,211.6
LIABILITIES AND EQUITY												
Current liabilities:												
Accounts payable	\$	1,532.1	\$	(841.2)	\$	(285.1)	\$	405.8	\$ 0.5	\$ _	\$	406.3
Accrued product payables		844.8		1,014.2		(13.3)		1,845.7	_	_		1,845.7
Other current liabilities		262.4		601.5		(14.7)		849.2	_	_		849.2
Total current liabilities		2,639.3		774.5		(313.1)		3,100.7	0.5	_		3,101.2
Long-term debt		8,567.0		3,070.9		_		11,637.9	_	_		11,637.9
Commitments and contingencies												
Other long-term liabilities		17.2		159.4		_		176.6	_	_		176.6
Equity:												
Controlling interests		6,211.8		16,476.0	(16,597.1)		6,090.7	6,089.5	(6,090.7)		6,089.5
Noncontrolling interests				3,176.1		40.9		3,217.0		(10.6)		3,206.4
Total equity		6,211.8		19,652.1	(16,556.2)		9,307.7	6,089.5	(6,101.3)		9,295.9
Total liabilities and equity	\$ 1	17,435.3	\$	23,656.9	\$ (16,869.3)	\$	24,222.9	\$ 6,090.0	\$ (6,101.3)	\$	24,211.6

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS

Year Ended December 31, 2009

		EPO AND SU	BSIDIARIES	_			
	SUBSIDIARY ISSUER (EPO)	OTHER Subsidiaries (non-guarantor)	EPO AND SUBSIDIARIES ELIMINATIONS AND ADJUSTMENTS	CONSOLIDATED EPO AND SUBSIDIARIES	PARENT COMPANY (GUARANTOR)	ELIMINATIONS AND ADJUSTMENTS	CONSOLIDATED Total
Revenues	\$18,986.8	\$14,496.0	\$ (7,971.9)	\$25,510.9	\$	\$ —	\$25,510.9
Costs and expenses:							
Operating costs and expenses	18,647.9	12,821.8	(7,903.9)	23,565.8	_	_	23,565.8
General and administrative costs	14.1	149.2	_	163.3	9.0	_	172.3
Total costs and expenses	18,662.0	12,971.0	(7,903.9)	23,729.1	9.0	_	23,738.1
Equity in income of unconsolidated affiliates	1,225.8	117.5	(1,292.1)	51.2	1,039.9	(1,039.9)	51.2
Operating income	1,550.6	1,642.5	(1,360.1)	1,833.0	1,030.9	(1,039.9)	1,824.0
Other income (expense):							
Interest expense	(514.1)	(140.4)	12.7	(641.8)	_	_	(641.8)
Other, net	8.5	2.4	(12.7)	(1.8)	_	_	(1.8)
Total other expense, net	(505.6)	(138.0)	_	(643.6)	_	_	(643.6)
Income before provision for income taxes	1,045.0	1,504.5	(1,360.1)	1,189.4	1,030.9	(1,039.9)	1,180.4
Provision for income taxes	(7.8)	(17.4)	_	(25.2)	_	(0.1)	(25.3)
Net income	1,037.2	1,487.1	(1,360.1)	1,164.2	1,030.9	(1,040.0)	1,155.1
Net income attributable to noncontrolling interest		21.6	(146.2)	(124.6)		0.4	(124.2)
Net income attributable to entity	\$ 1,037.2	\$ 1,508.7	\$ (1,506.3)	\$ 1,039.6	\$ 1,030.9	\$ (1,039.6)	\$ 1,030.9

Enterprise Products Partners L.P.

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS

Year Ended December 31, 2008

		EPO AND S	UBSIDIARIES				
	SUBSIDIARY ISSUER (EPO)	OTHER Subsidiaries (Non- Guarantor)	EPO AND SUBSIDIARIES ELIMINATIONS AND ADJUSTMENTS	CONSOLIDATED EPO AND SUBSIDIARIES	PARENT COMPANY (GUARANTOR)	ELIMINATIONS AND ADJUSTMENTS	CONSOLIDATED TOTAL
Revenues	\$ 23,348.2	\$ 21,729.0	\$ (9,607.6)	\$ 35,469.6	\$ —	\$ -	\$ 35,469.6
Costs and expenses:							
Operating costs and expenses	23,140.2	20,078.6	(9,599.9)	33,618.9	_	_	33,618.9
General and administrative costs	12.6	122.1		134.7	2.5		137.2
Total costs and expenses	23,152.8	20,200.7	(9,599.9)	33,753.6	2.5	_	33,756.1
Equity in income of unconsolidated affiliates	1,140.5	158.5	(1,264.1)	34.9	956.5	(956.5)	34.9
Operating income	1,335.9	1,686.8	(1,271.8)	1,750.9	954.0	(956.5)	1,748.4
Other income (expense):							
Interest expense	(386.6)	(166.2)	12.1	(540.7)	_	_	(540.7)
Other, net	21.1	0.4	(9.3)	12.2			12.2
Total other expense, net	(365.5)	(165.8)	2.8	(528.5)	_		(528.5)
Income before provision for income taxes	970.4	1,521.0	(1,269.0)	1,222.4	954.0	(956.5)	1,219.9
Provision for income taxes	(14.2)	(16.8)		(31.0)			(31.0)
Net income	956.2	1,504.2	(1,269.0)	1,191.4	954.0	(956.5)	1,188.9
Net income attributable to noncontrolling interest		(221.1)	(14.0)	(235.1)		0.2	(234.9)
Net income attributable to entity	\$ 956.2	\$ 1,283.1	\$ (1,283.0)	\$ 956.3	\$ 954.0	\$ (956.3)	\$ 954.0

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONSYear Ended December 31, 2007

		EPO AND SI	UBSIDIARIES		_		
	SUBSIDIARY ISSUER (EPO)	OTHER Subsidiaries (Non-Guarantor)	EPO AND SUBSIDIARIES ELIMINATIONS AND ADJUSTMENTS	CONSOLIDATED EPO AND SUBSIDIARIES	PARENT COMPANY (GUARANTOR)	ELIMINATIONS AND ADJUSTMENTS	CONSOLIDATED Total
Revenues	\$ 16,308.8	\$ 16,541.8	\$ (6,136.8)	\$26,713.8	\$ —	\$ -	\$26,713.8
Costs and expenses:							
Operating costs and expenses	16,257.6	15,270.5	(6,126.0)	25,402.1	_	_	25,402.1
General and administrative costs	26.5	98.2	_	124.7	2.5		127.2
Total costs and expenses	16,284.1	15,368.7	(6,126.0)	25,526.8	2.5	_	25,529.3
Equity in income of unconsolidated affiliates	800.4	108.5	(898.4)	10.5	534.3	(534.3)	10.5
Operating income	825.1	1,281.6	(909.2)	1,197.5	531.8	(534.3)	1,195.0
Other income (expense):							
Interest expense	(300.4)	(124.7)	12.1	(413.0)	_	_	(413.0)
Other, net	14.6	67.0	(11.7)	69.9	1.8	_	71.7
Total other expense, net	(285.8)	(57.7)	0.4	(343.1)	1.8	_	(341.3)
Income before provision for income taxes	539.3	1,223.9	(908.8)	854.4	533.6	(534.3)	853.7
Provision for income taxes	(5.0)	(10.7)	_	(15.7)	_	_	(15.7)
Net income	534.3	1,213.2	(908.8)	838.7	533.6	(534.3)	838.0
Net income attributable to noncontrolling interest		(305.6)	1.1	(304.5)		0.1	(304.4)
Net income attributable to entity	\$ 534.3	\$ 907.6	\$ (907.7)	\$ 534.2	\$ 533.6	\$ (534.2)	\$ 533.6

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS Year Ended December 31, 2009

		EPO AND S	UBSIDIARIES					
	SUBSIDIARY ISSUER (EPO)	OTHER SUBSIDIARIES (NON-GUARANTOR)	EPO AND SUBSIDIARIES ELIMINATIONS AND ADJUSTMENTS	CONSOLIDATED EPO AND SUBSIDIARIES	PARENT Company (Guarantor)	ELIMINATIONS AND ADJUSTMENTS	CONSOLIDATED TOTAL	
Operating activities:								
Net income Adjustments to reconcile net income to cash provided by operating activities: Depreciation, accretion and	\$ 1,037.2	\$ 1,487.1	\$ (1,360.1)		\$ 1,030.9	\$ (1,040.0)	\$1,155.1	
amortization Non-cash impairment charges	86.3	748.7 33.5	(1.6)	833.4 33.5	_	_	833.4 33.5	
Equity in income of unconsolidated affiliates	(1,225.8)	(117.5)	1 202 1		(1,039.9)	1,039.9	(51.2)	
Distributions received from unconsolidated affiliates	258.6	79.8	1,292.1 (251.8)	(51.2) 86.6	1,265.0	(1,265.0)	86.6	
Operating lease expenses paid by		79.0	(231.6)		1,265.0	(1,205.0)		
EPCO Loss on forfeiture of investment in	0.7	-	_	0.7	_	_	0.7	
TOPS Gain from asset sales and related	_	68.4	_	68.4	_	_	68.4	
transactions	_	0.3	(0.3)	_	_	_	_	
Deferred income tax expense	(0.9)	5.8	_	4.9	_	(0.4)	4.5	
Changes in fair market value of derivative instruments Effect of pension settlement	5.8	(5.4)	_	0.4	_	_	0.4	
recognition	_	(0.1)	_	(0.1)	_	_	(0.1)	
Net effect of changes in operating accounts	1,314.9	(856.7)	(208.8)	249.4	(3.7)	0.2	245.9	
Cash provided by operating activities	1,476.8	1,443.9	(530.5)	2,390.2	1,252.3	(1,265.3)	2,377.2	
Investing activities: Capital expenditures, net of contributions in aid of construction costs	(209.9)	(1,356.6)		(1,566.5)		_	(1,566.5)	
Decrease (increase) in restricted cash	140.7	(0.5)		140.2			140.2	
Cash used for business combinations	(23.7)	(93.9)	10.3	(107.3)		_	(107.3)	
Acquisition of intangible assets	(20.7)	(1.4)	_	(1.4)	_	_	(1.4)	
Investments in unconsolidated affiliates	(1,266.0)	(18.1)	1,265.3	(18.8)	(908.3)	908.3	(18.8)	
Proceeds from asset sales and related transactions	_	3.6	_	3.6	_	_	3.6	
Other investing activities	_	3.3	_	3.3	_	_	3.3	
Cash provided by (used in) investing activities	(1,358.9)	(1,463.6)	1,275.6	(1,546.9)	(908.3)	908.3	(1,546.9)	
Financing activities:								
Borrowings under debt agreements	6,105.0	1,271.6	_	7,376.6	_	_	7,376.6	
Repayments of debt Cash distributions paid to partners	(5,838.2) (1,265.1)	(1,815.3) (448.1)	448.1	(7,653.5) (1,265.1)	(1,254.8)	1,265.1	(7,653.5) (1,254.8)	
Cash distributions paid to partiers cash distributions paid to noncontrolling interest	(1,203.1)	(303.8)	(36.4)	(340.2)	(1,254.6)	0.2	(340.0)	
Net cash proceeds from issuance of common units		(303.0)	(30.4)	(340.2)	912.7	_	912.7	
Cash contributions from members	908.3	1,288.8	(1,288.8)	908.3	J12.7	(908.3)	J12.7	
Cash contributions from noncontrolling interest	_	3.5	135.2	138.7	_	(300.0) —	138.7	
Other financing activities	(14.5)	(0.2)	_	(14.7)	(2.1)	_	(16.8)	
Cash provided by (used in) financing activities	(104.5)	(3.5)	(741.9)	(849.9)	(344.2)	357.0	(837.1)	
Effect of exchange rate changes on cash		(0.2)	_	(0.2)	_	_	(0.2)	
Net change in cash and cash equivalents	13.4	(23.2)	3.2	(6.6)	(0.2)	_	(6.8)	
Cash and cash equivalents, January 1	1.0	69.7	(9.4)	61.3	0.2	0.2	61.7	
Cash and cash equivalents, December 31	\$ 14.4	\$ 46.3	\$ (6.2)	\$ 54.5	\$	\$ 0.2	\$ 54.7	

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS Year Ended December 31, 2008

	EPO AND SUBSIDIARIES						_				
	SUBSIDIARY ISSUER (EPO)	OTH Subsidi (No Guarai	ARIES N-	ELIMINATION AND	SUBSIDIARIES ELIMINATIONS CONSOLIDATED			NT COMPANY (ARANTOR)	ELIMINATIONS AND ADJUSTMENTS	CON	NSOLIDATED Total
Operating activities:											
Net income Adjustments to reconcile net income to cash provided by operating activities:	\$ 956.2	\$ 1,50	04.2	\$ (1,269.0	0) \$	1,191.4	\$	954.0	\$ (956.5)	\$	1,188.9
Depreciation, accretion and amortization	68.4	6	69.3	0.3	1	737.8		_	_		737.8
Equity in income of unconsolidated affiliates Distributions received from unconsolidated affiliates	(1,140.5)		58.5) 65.8)	1,264.	1	(34.9)		(956.5) 1,036.8	956.5 (1,036.8)		(34.9)
Operating lease expenses paid by EPCO	2.0		_	_	_	2.0		_	_		2.0
Gain from asset sales and related transactions	_		(4.0)	_	_	(4.0)		_	_		(4.0)
Loss (gain) on early extinguishment of debt	(7.1)		8.7	_	_	1.6		_	_		1.6
Deferred income tax expense Changes in fair market value of derivative	(0.4)		6.6	_	-	6.2		_	_		6.2
instruments	3.8		(3.9)	_	-	(0.1)		_	_		(0.1)
Effect of pension settlement recognition	(1.2)		1.1	_	_	(0.1)		_	_		(0.1)
Net effect of changes in operating accounts Cash provided by (used in) operating activities	(352.1)	-	66.5) 91.2	(1.5		(415.3) 1,565.4		3.2 1,037.5	(1,035.8)		1,567.1
Investing activities:											
Capital expenditures, net of contributions in aid of construction costs	(42.2)	(2,4	70.2)	_	-	(2,512.4)		_	_	((2,512.4)
Increase in restricted cash	(132.8)		_	-	-	(132.8)		_	_		(132.8)
Cash used for business combinations	(77.0)	(4)	76.5)	-	-	(553.5)		_	_		(553.5)
Acquisition of intangible assets	(5.1)		(0.7)	_	-	(5.8)		_	_		(5.8)
Investments in unconsolidated affiliates Proceeds from asset sales and related transactions	(584.1)		12.7 22.0	6.7	7	(64.7) 22.3		(141.0)	141.0		(64.7) 22.3
Cash provided by (used in) investing activities	(840.9)	(2,4	12.7)	6.7	7	(3,246.9)		(141.0)	141.0	((3,246.9)
Financing activities:											
Borrowings under debt agreements	8,284.6	4,9	03.4	_	_	13,188.0		_	_	1	3,188.0
Repayments of debt	(6,403.5)	(4,0	30.8)	_	- ((10,434.3)		_	_	(1	0,434.3)
Cash distributions paid to partners	(1,036.8)		_	_	_	(1,036.8)	(1,037.4)	1,036.8	((1,037.4)
Cash distributions paid to noncontrolling interest	_	(3	84.8)	_	-	(384.8)		_	0.9		(383.9)
Net cash proceeds from issuance of common units	_		_	_	_	_		142.8	_		142.8
Cash contributions from members	141.0		_	_	_	141.0		_	(141.0)		_
Cash contributions from noncontrolling interest	_	3	13.3	_	_	313.3		_	(1.8)		311.5
Other financing activities	(30.3)	(63.8)	_	_	(94.1)		(1.9)	_		(96.0)
Cash provided by (used in) financing activities	955.0	7:	37.3	_		1,692.3		(896.5)	894.9		1,690.7
Effect of exchange rate changes on cash	_		(0.5)	_	-	(0.5)		_	_		(0.5)
Net change in cash and cash equivalents	(10.2)		15.8	5.2	2	10.8		_	0.1		10.9
Cash and cash equivalents, January 1	11.2		54.4	(14.6		51.0	_	0.2	0.1		51.3
Cash and cash equivalents, December 31	\$ 1.0	\$	69.7	\$ (9.4	4) \$	61.3	\$	0.2	\$ 0.2	\$	61.7

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS Year Ended December 31, 2007

		EPO AND S	SUBSIDIARIES				
	SUBSIDIARY ISSUER (EPO)	OTHER Subsidiaries (Non- Guarantor)	EPO AND SUBSIDIARIES ELIMINATIONS AND ADJUSTMENTS	CONSOLIDATED EPO AND SUBSIDIARIES	PARENT COMPANY (GUARANTOR)	ELIMINATIONS AND ADJUSTMENTS	CONSOLIDATED TOTAL
Operating activities:							
Net income Adjustments to reconcile net income to cash provided by operating activities:	\$ 534.3	\$1,213.2	\$ (908.8)	\$ 838.7	\$ 533.6	\$ (534.3)	\$ 838.0
Depreciation, accretion and amortization	62.2	595.9	0.3	658.4	_	_	658.4
Equity in income of unconsolidated affiliates Distributions received from unconsolidated affiliates	(800.4) 924.6	(108.5) (837.6)	898.4	(10.5) 87.0	(534.3) 946.9	534.3 (946.9)	(10.5) 87.0
Operating lease expenses paid by EPCO Loss (gain) from asset sales and related transactions	2.1 5.8	(73.2)	_	2.1 (67.4)	_	_	2.1 (67.4)
Loss on early extinguishment of debt	_	1.6	_	1.6	_	_	1.6
Deferred income tax expense	2.4	5.2	_	7.6	_	_	7.6
Changes in fair market value of derivative instruments	0.4	0.9	_	1.3	_	_	1.3
Effect of pension settlement recognition	0.4	0.2	_	0.6	_	_	0.6
Net effect of changes in operating accounts	(830.0)	1,244.5	8.0	422.5	9.8	2.6	434.9
Cash provided by operating activities	(98.2)	2,042.2	(2.1)	1,941.9	956.0	(944.3)	1,953.6
Investing activities: Capital expenditures, net of contributions in aid of construction costs	(170.7)	(2,535.7)	_	(2,706.4)	_	_	(2,706.4)
Decrease (increase) in restricted cash	(66.3)	19.0	_	(47.3)	_	_	(47.3)
Cash used for business combinations	(0.3)	(35.6)	_	(35.9)	_	_	(35.9)
Acquisition of intangible assets	(11.2)	(3.3)	_	(14.5)	_	_	(14.5)
Investments in unconsolidated affiliates Proceeds from asset sales and related transactions	(114.7)	(125.6) 169.0	3.5	(236.8) 169.1	(67.6)	67.6	(236.8) 169.1
Cash provided by (used in) investing activities	(363.1)	(2,512.2)	3.5	(2,871.8)	(67.6)	67.6	(2,871.8)
Financing activities:							
Borrowings under debt agreements	5,643.5	1,986.3	_	7,629.8	_	_	7,629.8
Repayments of debt	(4,329.0)	(1,462.0)	(8.9)	(5,799.9)	_	_	(5,799.9)
Cash distributions paid to partners Cash distributions paid to noncontrolling	(946.9)	_	_	(946.9)	(957.7)	946.9	(957.7)
interest Net cash proceeds from issuance of common	_	(326.8)	_	(326.8)	-	_	(326.8)
units	67.6	_	_	-	69.2	(67.6)	69.2
Cash contributions from members	67.6	306.9	_	67.6 306.9	_	(67.6) (2.2)	304.7
Cash contributions from noncontrolling interest Other financing activities	31.7	(4.7)	_	27.0		(2.2)	27.0
Cash provided by (used in) financing activities	466.9	499.7	(8.9)	957.7	(888.5)	877.1	946.3
Effect of exchange rate changes on cash		0.4		0.4	_		0.4
Net change in cash and cash equivalents	5.6	29.7	(7.5)	27.8	(0.1)	0.4	28.1
Cash and cash equivalents, January 1	5.6	24.3	(7.1)	22.8	0.3	(0.3)	22.8
Cash and cash equivalents, December 31	\$ 11.2	\$ 54.4	\$ (14.6)	\$ 51.0	\$ 0.2	\$ 0.1	\$ 51.3

NOTE 23. SUBSEQUENT EVENT

Enterprise Products Partners Issues \$343.1 Million of Common Units

In January 2010, we issued 10,925,000 common units (including an over-allotment of 1,425,000 common units) to the public at an offering price of \$32.42 per unit. We used the net cash proceeds of \$343.1 million to temporarily reduce borrowings outstanding under EPO's Multi-Year Revolving Credit Facility, which may be reborrowed to fund capital expenditures and other growth projects, and for general partnership purposes.

RECONCILIATION OF GAAP FINANCIAL STATEMENTS TO NON-GAAP FINANCIAL MEASURES

	FOR YEAR ENDED DECEMBER 31,				31,	
		2009		2008		2007
Reconciliation of Non-GAAP "Adjusted EBITDA" to GAAP "Net income" and GAAP						
<u>"Net cash flows provided by operating activities"</u> Net Income	\$	1,155.1	\$	1,188.9	\$	838.0
Additions to net income to derive Adjusted EBITDA:	Ψ	1,100.1	Ψ	1,100.5	Ψ	000.0
Equity in income of unconsolidated affiliates		(51.2)		(34.9)		(10.5)
Distributions received from unconsolidated affiliates		86.6		80.8		87.0
Interest expense		641.8		540.7		413.0
Provision for income taxes		25.3		31.0		15.7
Depreciation, amortization and accretion in operating costs and expenses		828.5		739.6		661.4
Adjusted EBITDA	\$	2,686.1	\$	2,546.1	\$	2,004.6
Adjustments to Adjusted EBITDA to derive net cash flows provided by operating activities:		,		, -		,
Interest expense		(641.8)		(540.7)		(413.0)
Amortization in interest expense		4.9		(1.8)		(3.0)
Provision for income taxes		(25.3)		(31.0)		(15.7)
Gain from asset sales and related transactions		_		(4.0)		(67.4)
Non-cash impairment charge		33.5		_		_
Loss on forfeiture of investment in Texas Offshore Port System		68.4		_		_
Operating lease expense paid by EPCO		0.7		2.0		2.1
Deferred income tax expense		4.5		6.2		7.6
Changes in fair market value of derivative instruments		0.4		(0.1)		1.3
Effect of pension settlement recognition		(0.1)		(0.1)		0.6
Loss on the early extinguishment of debt		_		1.6		1.6
Net effect of changes in operating accounts		245.9		(411.1)		434.9
Net Cash Flows Provided by Operating Activities	\$	2,377.2	\$	1,567.1	\$	1,953.6
Reconciliation of Non-GAAP "Distributable cash flow" to GAAP "Net income attributable to Enterprise Products Partners L.P." and GAAP "Net cash flows provided by operating activities"						
Net Income attributable to Enterprise Products Partners L.P.	\$	1,030.9	\$	954.0	\$	533.6
Adjustments to Net Income attributable to Enterprise Products Partners L.P. to derive distributable cash flow:						
Depreciation, amortization and accretion		725.5		562.2		523.8
Operating lease expense paid by EPCO		0.7		2.0		2.1
Monetization of interest rate hedging derivative instruments		0.2		(14.4)		48.9
Amortization of net gains related to monetization of derivative instruments		1.0		(4.4)		(4.0)
Equity in income of unconsolidated affiliates		(61.4)		(59.1)		(29.7)
Distributions received from unconsolidated affiliates		127.4		98.6		73.6
Loss (gain) from asset sales and related transactions		0.1		(3.7)		5.4
Proceeds from asset sales and related transactions		3.5		16.0		12.0
Sustaining capital expenditures		(166.6)		(188.7)		(162.5)
El Paso transition support payments						9.0
Net income attributable to noncontrolling interests - DEP public unitholders		31.3		17.2		13.9
Distribution to be paid to DEP public unitholders with respect to period		(38.0)		(25.1)		(21.9)
Cash expenditures for asset abandonment activities		(12.4)		(7.2)		(5.0)
Net loss of TEPPCO for third quarter 2009		(42.1)				_
Other miscellaneous adjustments to derive distributable cash flow		43.1	Φ.	30.8	Φ.	2.0
Distributable Cash Flow (1)	\$	1,643.2	\$	1,378.2	\$	1,001.2
Adjustments to distributable cash flow to derive net cash flows provided by operating activities:		(0.0)		14.4		(40.0)
Monetization of interest rate hedging derivative instruments		(0.2)		14.4		(48.9)
Amortization of net gains related to monetization of derivative instruments		(1.0)		4.4		4.0
Proceeds from asset sales and related transactions		(3.5) 166.6		(16.0) 188.7		(12.0) 162.5
Sustaining capital expenditures		100.0		100.7		
El Paso transition support payments Net income attributable to noncontrolling interests		75.7		41.4		(9.0)
Net income attributable to noncontrolling interests - DEP public unitholders		(31.3)		41.4 (17.2)		30.6 (13.9)
Distribution to be paid to DEP public unitholders with respect to period		38.0		25.1		21.9
Cash expenditures for asset abandonment activities		12.4		7.2		5.0
Miscellaneous non-cash and other amounts to reconcile distributable cash		14.4		1.2		5.0
flow with net cash flows provided by operating activities		(5.2)		(31.6)		8.2
Net effect of changes in operating accounts		284.7		(357.4)		441.3
Operating cash flows for the six months ended June 30, 2009 attributable		201.7		(557.4)		
to the inclusion of TEPPCO amounts in our recast financial statements		197.8		_		_
Net Cash Flows Provided by Operating Activities	\$	2,377.2	\$	1,237.2	\$	1,590.9
	_					

⁽¹⁾ Distributable cash flow for 2009 includes amounts attributable to TEPPCO Partners, L.P. for the third and fourth quarters. Accordingly, our 2009 distributable cash flow is calculated and reconciled to the recast financial results of Enterprise Products Partners L.P., which includes amounts attributable to TEPPCO Partners, L.P. and its consolidated subsidiaries prior to October 26, 2009. Distributable cash flow for periods prior to 2009 is calculated based on and reconciled to the historical financial results (pre-recast) for Enterprise Products Partners L.P.

DIRECTORS AND OFFICERS OF ENTERPRISE PRODUCTS GP, LLC

Michael A. Creel
President and Chief
Executive Officer

W. Randall Fowler
Executive Vice President
and Chief Financial
Officer

Richard H. Bachmann Executive Vice President, Chief Legal Officer and Secretary

A.J. "Jim" TeagueExecutive Vice President and Chief Commercial
Officer

E. William Barnett (1)(2)
Director

Dr. Ralph Cunningham Director

Director

Rex C. Ross (1)

Director

Charles M. Rampacek (1)

OFFICERS OF ENTERPRISE PRODUCTS GP, LLC AND EPE HOLDINGS, LLC WHO PROVIDE SERVICES TO ENTERPRISE PRODUCTS PARTNERS L.P.

William OrdemannExecutive Vice President and Chief Operating

Officer

Lynn L. Bourdon, III Senior Vice President

Bryan F. Bulawa

Senior Vice President and Treasurer

James A. Cisarik Senior Vice President

James M. Collingsworth Senior Vice President

Terrance L. Hurlburt Senior Vice President

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Michael J. Knesek Senior Vice President, Controller and Principal Accounting Officer

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Information Officer

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James D. Gernentz (3)
Vice President

James F. Guion Vice President

James F. Healey Vice President

Stephanie C. HildebrandtVice President and
General Counsel

Richard G. Hutchison (3) Vice President

Russell H. Kovin Vice President

Albert A. Martinez, Jr. Vice President

James N. McGrew Vice President and Assistant Controller

Patrick R. McMurry Vice President **D. Bartlett Moore, Jr.** Vice President

Eugene L. Petru (3) Vice President

Leonard G. Price Vice President

J. Mario Rivera Vice President

Randall F. Scheirman Vice President

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Jack D. Vickrey Vice President

Gregory W. Watkins (3) Vice President

A. Monty Wells Vice President

Abid Yousuf (3) Vice President

Mark D. Youtsey Vice President

- (1) Member of ACG Committee
- (2) Chairman of ACG
- (3) Officer of EPE Holdings, LLC

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Enterprise Products Partners L.P. ("Enterprise") common units trade on the New York Stock Exchange under the ticker symbol EPD. Enterprise had 603,202,828 common units, 2,720,882 restricted common units and 4,520,431 Class B units outstanding at December 31, 2009. For a complete description of these units, see page 75. For a table of the high-and low-market prices of the common units by quarter, see page 21.

CASH DISTRIBUTIONS

Enterprise has paid 46 consecutive quarterly cash distributions to unitholders since its initial public offering of common units in 1998. On January 12, 2010, the partnership declared a quarterly distribution of \$0.56 per unit. This distribution was paid to unitholders of record at the close of business on February 4, 2010. For a summary of the cash distributions paid, see page 79.

PUBLICLY TRADED PARTNERSHIP ATTRIBUTES

Enterprise is a publicly traded limited partnership, which operates in the following ways that are different from a publicly traded stock corporation:

- Unitholders own limited partnership units instead of shares of common stock and receive cash distributions rather than dividends.
- -- A partnership generally is not a taxable entity and does not pay federal income taxes. All of the annual income, gains, losses, deductions or credits flow through the partnership to the unitholders on a per unit basis. The unitholders are required to report their allocated share of these amounts on their income tax returns whether or not any cash distributions are paid by the partnership to its unitholders.
- -- Cash distributions paid by a partnership to a unitholder are generally not taxable, unless the amount of any cash distributed is in excess of the unitholder's adjusted basis in their partnership interest.

K-1 INFORMATION

Enterprise provides each unitholder a Schedule K-1 tax package that includes each unitholder's allocated share of reportable partnership items and other partnership information necessary to be reported on state and federal income tax returns. The K-1 provides required tax information for a unitholder's ownership interest in the partnership, just as a Form 1099-DIV does for a stockholder's ownership interest in a corporation.

Information concerning the partnership's K-1s can be obtained by calling toll free 1.800.599.9985 or through the partnership's website at www.epplp.com.

REGISTERED PUBLIC ACCOUNTING FIRM

Deloitte & Touche LLP Houston, TX

TRANSFER AGENT, REGISTRAR AND CASH DISTRIBUTION PAYING AGENT

BNY Mellon Shareowner Services 480 Washington Blvd., 27th Floor Jersey City, NJ 07310-1900 1.800.635.9270

www.bnymellon.com/shareowner/isd

ADDITIONAL INVESTOR INFORMATION

Additional information about Enterprise, including our SEC annual report on Form 10-K, can be obtained by contacting Investor Relations by telephone at 1.866.230.0745, writing to the partnership's mailing address or accessing the partnership's website provided below.

HEADQUARTERS

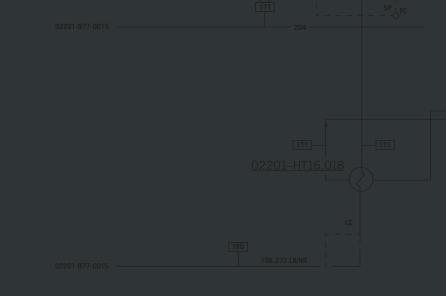
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