MARTIN MIDSTREAM PARTNERS LP
Form 10-K
March 02, 2011

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

FORM 10-K

Mark One	
x	Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
	For the fiscal year ended December 31, 2010
	OR
o	Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the transition period from _____ to _____.
Commission file number 000-50056

MARTIN MIDSTREAM PARTNERS L.P.
(Exact name of registrant as specified in its charter)

Delaware	05-0527861
State or other jurisdiction of incorporation or organization	(I.R.S. Employer Identification No.)

4200 Stone Road Kilgore, Texas 75662
(Address of principal executive offices) (Zip Code)

903-983-6200
(Registrant's telephone number, including area code)

Securities Registered Pursuant to Section 12(b) of the Act:

NONE

Securities Registered Pursuant to Section 12(g) of the Act:

Title of each class	Name of each exchange on which registered
Common Units representing limited partnership interests	NASDAQ

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Yes o No x

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

Yes o No x

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

Yes x No o

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

Yes o No o

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See definition of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

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

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

Yes o No x

As of June 30, 2010, 17,707,832 common units were outstanding. The aggregate market value of the common units held by non-affiliates of the registrant as of such date approximated $206,544,787 based on the closing sale price on that date. There were 19,582,332 of the registrant's common units and 889,444 of the registrant's subordinated units outstanding as of March 2, 2011.

DOCUMENTS INCORPORATED BY REFERENCE: None.

TABLE OF CONTENTS

Table of Contents

PART I

Item 1. Business

Overview

We are a publicly traded limited partnership with a diverse set of operations focused primarily in the United States Gulf Coast region. Our four primary business lines include:

- Terminalling and storage services for petroleum products and by-products;
- Natural gas services;
- Sulfur and sulfur-based products gathering, processing, marketing , manufacturing and distribution; and
- Marine transportation services for petroleum products and by-products.

The petroleum products and by-products we gather, process, transport, store and market are produced primarily by major and independent oil and gas companies who often turn to third parties, such as us, for the transportation and disposition of these products. In addition to these major and independent oil and gas companies, our primary customers include independent refiners, large chemical companies, fertilizer manufacturers and other wholesale purchasers of these products. We generate the majority of our cash flow from fee-based contracts with these customers. Our location in the Gulf Coast region of the United States provides us strategic access to a major hub for petroleum refining, natural gas gathering and processing and support services for the exploration and production industry.

We were formed in 2002 by Martin Resource Management Corporation ("Martin Resource Management"), a privately-held company whose initial predecessor was incorporated in 1951 as a supplier of products and services to drilling rig contractors. Since then, Martin Resource Management has expanded its operations through acquisitions and internal expansion initiatives as its management identified and capitalized on the needs of producers and purchasers of hydrocarbon products and by-products and other bulk liquids. As of March 2, 2011, Martin Resource Management owns an approximate 31.6% limited partnership interest in us. Furthermore, it owns and controls our general partner, which owns a 2.0% general partner interest and incentive distribution rights in us.

The historical operation of our business segments by Martin Resource Management provides us with several decades of experience and a demonstrated track record of customer service across our operations. Our current lines of business have been developed and systematically integrated over this period of more than 60 years, including natural gas services (1950s); sulfur (1960s); marine transportation (late 1980s) and terminalling and storage (early 1990s). This development of a diversified and integrated set of assets and operations has produced a complementary portfolio of midstream services that facilitates the maintenance of long-term customer relationships and encourages the development of new customer relationships.

Primary Business Segments

Our primary business segments can be generally described as follows:

- Terminalling and Storage. We own or operate 27 marine shore based terminal facilities and 12 specialty terminal facilities located in the United States Gulf Coast region that provide storage, processing and handling services for producers and suppliers of petroleum products and by-products, lubricants and other liquids, including the refining of various grades and quantities of naphthenic lubricants and related products. As further described in the "Subsequent Events" section within this Item, 13 of our marine shore based terminals and one of our specialty terminals were acquired January 31, 2011 through our acquisition of certain terminalling assets from Martin Resource Management. Our facilities and resources provide us with the ability to handle various products that require specialized treatment, such as molten sulfur and asphalt. We also provide land rental to oil and gas companies along with storage and handling services for lubricants and fuel oil. We provide these terminalling and storage services on a fee basis primarily under long-term contracts. A significant portion of the contracts in this segment provide for minimum fee arrangements that are not based on the volumes handled.

- Natural Gas Services. Through our acquisitions of Prism Gas Systems I, L.P. ("Prism Gas") and Woodlawn Pipeline Co., Inc. ("Woodlawn"), we have ownership interests in over 706 miles of gathering and transmission pipelines located in the natural gas producing regions of East Texas, Northwest Louisiana, the Texas Gulf Coast and offshore Texas and federal waters in the Gulf of Mexico, as well as a 285 MMcfd capacity natural gas processing plant located in East Texas. In addition to our natural gas gathering and processing business, we distribute natural gas liquids or, "NGLs". We purchase NGLs primarily from natural gas processors. We store NGLs in our supply and storage facilities for wholesale deliveries to propane retailers, refineries and industrial NGL users in Texas and the Southeastern United States. We own an NGL pipeline which spans approximately 200 miles running from Kilgore to Beaumont, Texas. We own three NGL supply and storage facilities with an aggregate above-ground storage capacity of approximately 3,000 barrels and we lease approximately 2.6 million barrels of underground storage capacity for NGLs. We believe we have a natural gas processing competitive advantage in East Texas with the only full fractionation facilities serving this area. The recent acquisition of natural gas gathering and processing assets from Crosstex Energy, L.P. and Crosstex Energy, Inc. by Waskom Gas Processing Company (a joint venture in which we participate with Center Point Energy Gas Processing Company, an indirect, wholly-owned subsidiary of CenterPoint Energy, Inc.) and the Darco Gathering System further strengthens our East Texas infrastructure.

Table of Contents

- Sulfur Services. We have developed an integrated system of transportation assets and facilities relating to sulfur services over the last 30 years. We process and distribute sulfur predominantly produced by oil refineries primarily located in the United States Gulf Coast region. We handle molten sulfur on contracts that are tied to sulfur indices and tend to provide stable margins. We process molten sulfur into prilled or pelletized sulfur on take or pay fee contracts at our facilities in Port of Stockton, California and Beaumont, Texas. The sulfur we process and handle is primarily used in the production of fertilizers and industrial chemicals. We own and operate six sulfur-based fertilizer production plants and one emulsified sulfur blending plant that manufacture primarily sulfur-based fertilizer products for wholesale distributors and industrial users. These plants are located in Illinois, Texas and Utah. We own and operate a sulfuric acid production plant in Plainview, Texas which processes molten sulfur into sulfuric acid. Demand for our sulfur products exists in both the domestic and foreign markets, and we believe our asset base provides us with additional opportunities to handle increases in U.S. supply and access to foreign demand.

- Marine Transportation. We utilize a fleet of 44 inland marine tank barges, 18 inland push boats and four offshore tug barge units that transport petroleum products and by-products largely in the United States Gulf Coast region. We provide these transportation services on a fee basis primarily under annual contracts and many of our customers have long standing contractual relationships with us. Over the past several years, we have focused on modernizing our fleet. As a result, the average age of our vessels has decreased from 33 years in 2006 to 20 years as of March 2, 2011. This modernized asset base is attractive both to our existing customers as well as potential new customers. In addition, our fleet contains several vessels that reflect our focus on specialty products.

2010 Developments and Subsequent Events

Recent Acquisitions

Acquisition of the Darco Gathering System. On November 12, 2010, we, through our wholly owned subsidiary, Prism Gas, acquired approximately 20 miles of natural gas gathering pipeline and various equipment located in Harrison County, Texas for approximately $25.0 million. We financed this acquisition with borrowings under our revolving loan facility.

Acquisition by Waskom of the Harrison Pipeline System. On January 15, 2010, we, through Prism Gas, as 50% owner and the operator of Waskom Gas Processing Company (“WGPC”), through WGPC’s wholly owned subsidiary Waskom Midstream LLC, acquired from Crosstex North Texas Gathering, L.P., a 100% interest in approximately 62 miles of gathering pipeline, two 35 MMcfd dew point control plants and equipment referred to as the Harrison Pipeline System. Our share of the acquisition cost was approximately $20.0 million.

Other Developments

Public Offerings. On August 17, 2010, we completed a public offering of 1,000,000 common units, resulting in net proceeds of approximately $28.1 million after payment of underwriters’ discounts. We used the net proceeds of $28.1 million to redeem from subsidiaries of Martin Resource Management an aggregate number of common units equal to the number of common units issued in the offering. Martin Resource Management reimbursed us for our payments of commissions and offering expenses. As a result of these transactions, our general partner was not required to contribute cash to us in conjunction with the issuance of these units in order to maintain its 2% general partner interest in us since there was no net increase in the outstanding limited partner units.

Table of Contents

On February 8, 2010, we completed a public offering of 1,650,000 common units, resulting in net proceeds of $50.6 million, after payment of underwriters' discounts, commissions and offering expenses. Our general partner contributed $1.1 million in cash to us in conjunction with the issuance in order to maintain its 2% general partner interest in us. The net proceeds were used to pay down revolving debt under our credit facility.

Debt Financing Activities. Effective March 26, 2010, our credit facility was amended to (i) decrease the size of our aggregate facility from $350.0 million to $275.0 million, (ii) convert all term loans to revolving loans, (iii) extend the maturity date from November 9, 2012 to March 15, 2013, (iv) permit us to invest up to $40.0 million in our joint ventures, (v) eliminate the covenant that limits our ability to make capital expenditures, (vi) decrease the applicable interest rate margin on committed revolver loans, (vii) limit our ability to make future acquisitions and (viii) adjust the financial covenants.

On March 26, 2010, we completed a private placement of $200.0 million in aggregate principal amount of 8.875% senior unsecured notes due 2018 ("2018 Notes") to qualified institutional buyers under Rule 144A. We received proceeds of approximately $197.2 million, after deducting initial purchasers' discounts and the expenses of the private placement. The proceeds were primarily used to repay borrowings under the Partnership's revolving credit facility. Pursuant to the terms of a registration rights agreement entered into in connection with the offering of the 2018 Notes, we filed an exchange offer registration statement with the SEC on September 16, 2010 with respect to an offer to exchange the 2018 Notes for registered notes with substantially identical terms. The registration statement was declared effective by the SEC and the exchange offer was completed in the fourth quarter of 2010.

For a more detailed discussion regarding our credit facility, see "Description of Our Long-Term Debt—Senior Notes" in Item 7.

Subsequent Events

Public Offering. On February 9, 2011, we completed a public offering of 1,874,500 common units, resulting in net proceeds of $70.7 million after payment of underwriters' discounts, commissions and offering expenses. Our general partner contributed $1.5 million in cash to us in conjunction with the issuance of these units in order to maintain its 2% general partner interest in us. The net proceeds were used to pay down revolving debt under our credit facility.

Acquisition of Certain Terminalling Assets. On January 31, 2011, we acquired 13 shore-based marine terminalling facilities, one specialty terminalling facility and certain terminalling related assets from Martin Resource Management for $36.5 million. The net book value of the acquired assets was recorded in property, plant and equipment. These assets are located across the Louisiana Gulf Coast.

Quarterly Distribution. On January 24, 2011, we declared a quarterly cash distribution of $0.76 per common unit for the fourth quarter of 2010, or $3.04 per common unit on an annualized basis, to be paid on February 14, 2011 to unitholders of record as of February 3, 2011, reflecting a $0.01 increase over the quarterly distribution paid in respect to the third quarter of 2010.

Business Strategy

The key components of our business strategy are to:

- Pursue Organic Growth Projects. We continually evaluate economically attractive organic expansion opportunities in new or existing areas of operation that will allow us to leverage our existing market position, increase the distributable cash flow from our existing assets through improved utilization and efficiency, and leverage our existing customer base.

- Pursue Internal Organic Growth by Attracting New Customers and Expanding Services Provided to Existing Customers. We seek to identify and pursue opportunities to expand our customer base across all of our business segments. We generally begin a relationship with a customer by transporting or marketing a limited range of products and services. We believe expanding our customer base and our service and product offerings to existing customers is the most efficient and cost effective method of achieving organic growth in revenues and cash flow. We believe significant opportunities exist to expand our customer base and provide additional services and products to existing customers.

Table of Contents

- Pursue Strategic Acquisitions. We monitor the marketplace to identify and pursue accretive acquisitions that expand the services and products we offer or that expand our geographic presence. After acquiring other businesses, we will attempt to utilize our industry knowledge, network of customers and suppliers and strategic asset base to operate the acquired businesses more efficiently and competitively, thereby increasing revenues and cash flow. We believe that our diversified base of operations provides multiple platforms for strategic growth through acquisitions.

- Pursue Strategic Alliances. Many of our larger customers are establishing strategic alliances with midstream service providers such as us to address logistical and transportation problems or achieve operational synergies. These strategic alliances are typically structured differently than our regular commercial relationships, with the goal that such alliances would expand our business relationships with our customers and suppliers. We intend to pursue strategic alliances with customers in the future.

- Expand Geographically. We work to identify and assess other attractive geographic markets for our services and products based on the market dynamics and the cost associated with penetration of such markets. We typically enter a new market through an acquisition or by securing at least one major customer or supplier and then dedicating or purchasing assets for operation in the new market. Once in a new territory, we seek to expand our operations within this new territory both by targeting new customers and by selling additional services and products to our original customers in the territory.

Competitive Strengths

We believe we are well positioned to execute our business strategy because of the following competitive strengths:

§Asset Base and Integrated Distribution Network. We operate a diversified asset base that, together with the services provided by Martin Resource Management, enables us to offer our customers an integrated distribution network consisting of transportation, terminalling and midstream logistical services while minimizing our dependence on the availability and pricing of services provided by third parties. Our integrated distribution network enables us to provide customers a complementary portfolio of transportation, terminalling, distribution and other midstream services for petroleum products and by-products.

§Strategically Located Assets. We believe we are one of the largest providers of shore bases and one of the largest lubricant distributors and marketers in the United States Gulf Coast region. In addition, we are one of the largest operators of marine service terminals in the United States Gulf Coast region providing broad geographic coverage and distribution capability of our products and services to our customers. Our natural gas gathering and processing assets are focused in areas that have continued to experience high levels of drilling activity and natural gas production.

§Specialized Transportation Equipment and Storage Facilities. We have the assets and expertise to handle and transport certain petroleum products and by-products with unique requirements for transportation and storage, such as molten sulfur and asphalt. For example, we own facilities and resources to transport molten sulfur and asphalt, which must be maintained at temperatures between approximately 275 and 350 degrees Fahrenheit to remain in liquid form. We believe these capabilities help us enhance relationships with our customers by offering them services to handle their unique product requirements.

§Ability to Grow Our Natural Gas Gathering and Processing Services. We believe that, with our Prism Gas assets, we have opportunities for organic growth in our natural gas gathering and processing operations through increasing fractionation capacity, pipeline expansions, new pipeline construction and bolt-on acquisitions. We believe Prism’s assets are well situated in the Haynesville Shale which is one of the four largest U.S. shale deposits.

§Experienced Management Team and Operational Expertise. Members of our executive management team and the heads of our principal business lines have, on average, more than 30 years of experience in the industries in which we operate. Further, these individuals have been employed by Martin Resource Management, on average, for more than 18 years. Our management team has a successful track record of creating internal growth and completing acquisitions. We believe our management team’s experience and familiarity with our industry and businesses are important assets that assist us in implementing our business strategies.

- §Strong Industry Reputation and Established Relationships with Suppliers and Customers. We believe we have established a reputation in our industry as a reliable and cost-effective supplier of services to our customers and have a track record of safe, efficient operation of our facilities. Our management has also established long-term relationships with many of our suppliers and customers. We believe we benefit from our management's reputation and track record, and from these long-term relationships.

- §Financial Strength and Flexibility. We have historically financed our operations with a combination of debt and equity while maintaining a modest leverage profile, even in challenging business environments. Since our initial public offering, we have accessed the public equity markets six times for $334.6 million in total net proceeds, including capital contributions from our general partner. We have also occasionally issued units to Martin Resource Management in exchange for cash or assets.

- §Fee-Based Contracts and Active Commodity Risk Management. We generate a majority of our cash flow from fee-based contracts with our customers. In addition, a significant portion of these fee-based contracts consist of reservation charges or minimum fee arrangements, which reduce the volatility of a portion of cash flows to volume fluctuations. We seek to further minimize our exposure to commodity price fluctuations through swaps for crude oil, natural gas and natural gas liquids. As of December 31, 2010, Prism Gas has hedged approximately 37% and 10% of its commodity risk by volume for 2011 and 2012, respectively. As of March 2, 2011, Prism Gas has hedged approximately 45% and 14% of its commodity risk by volume for 2011 and 2012, respectively.

Terminalling and Storage Segment

Industry Overview. The United States petroleum distribution system moves petroleum products and by-products from oil refinery and natural gas processing facilities to end users. This distribution system is comprised of a network of terminals, storage facilities, pipelines, tankers, barges, rail cars and trucks. Terminals play a key role in moving these products throughout the distribution system by providing storage, blending and other ancillary services.

In the 1990s, the petroleum industry entered a period of consolidation. Refiners and marketers developed large-scale, cost-efficient operations resulting in several refinery acquisitions, combinations, alliances and joint ventures. This consolidation resulted in major oil companies integrating the various components of their businesses, including terminalling and storage. However, major integrated oil companies later concentrated their focus and resources on their core competencies of exploration, production, refining and retail marketing and examined ways to lower their distribution costs. Additionally, the Federal Trade Commission required some divestitures of terminal assets in markets in which merged companies, alliances and joint ventures were regarded as having excessive market power. As a result of these factors, oil and gas companies began to increasingly rely on third parties such as us to perform many terminalling and storage services.

Although many large energy and chemical companies own terminalling and storage facilities, these companies also use third-party terminalling and storage services. Major energy and chemical companies typically have a strong demand for terminals owned by independent operators when such terminals are strategically located at or near key transportation links, such as deep-water ports. Major energy and chemical companies also need independent terminal storage when their owned storage facilities are inadequate, either because of lack of capacity, the nature of the stored material or specialized handling requirements.

The Gulf Coast region is a major hub for petroleum refining. Approximately two-thirds of United States refining capacity expansion in the 1990s occurred in this region. Growth in the refining and natural gas processing industries has increased the volume of petroleum products and by-products that are transported within the Gulf Coast region, which consequently has increased the need for terminalling and storage services.

The marine and offshore oil and gas exploration and production industries use terminal facilities in the Gulf Coast region as shore bases that provide them logistical support services as well as provide a broad range of products, including fuel oil, lubricants, chemicals and supplies. The demand for these types of terminals, services and products is driven primarily by offshore exploration, development and production in the Gulf of Mexico. Offshore activity is greatly influenced by current and projected prices of oil and natural gas.

Marine Shore Based Terminals. We own or operate 27 marine shore based terminals along the Gulf Coast from Theodore, Alabama to Corpus Christi, Texas. Of our 27 marine shore based terminals, 13 were acquired on January 31, 2011 through our acquisition of certain terminalling assets from Martin Resource Management. Our terminal assets are located at strategic distribution points for the products we handle and are in close proximity to our customers.

Table of Contents

We are one of the largest operators of marine shore based terminals in the Gulf Coast region. These terminals are used to distribute and market lubricants and the full service terminals also provide shore bases for companies that are operating in the offshore exploration and production industry. Customers are primarily oil and gas exploration and production companies and oilfield service companies, such as drilling fluid companies, marine transportation companies and offshore construction companies. Shore bases typically provide logistical support, including the storing and handling of tubular goods, loading and unloading bulk materials, providing facilities from which major and independent oil companies can communicate with and control offshore operations and leasing dockside facilities to companies which provide complementary products and services such as drilling fluids and cementing services. We generate revenues from our terminals that have shore bases by fees that we charge our customers under land rental contracts for the use of our terminal facility for these shore bases. These contracts generally provide us a fixed land rental fee and additional rental fees that are determined based on a percentage of the sales value of the products and services delivered from the shore base. In addition, Martin Resource Management, through contractual arrangements, pays us for terminalling and storage of fuel oil and lubricants at these terminal facilities.

Our 27 marine shore based terminals are divided into two classes of terminals: (i) full service terminals and (ii) fuel and lubricant terminals.

Full Service Terminals. We own or operate fifteen full service terminals. These terminal facilities provide logistical support services and provide storage and handling services for fuel oil and lubricants. The significant difference between our full service terminals and our fuel and lubricant terminals is that our full service terminals generate additional revenues by providing shore bases to support our customer’s operating activities related to the offshore exploration and production industry. One typical use for our shore bases is for drilling fluids manufacturers to manufacture and sell drilling fluids to the offshore drilling industry. Offshore drilling companies may also set up service facilities at these terminals to support their offshore operations. Customers of our full service terminals are primarily oil and gas exploration and production companies, and oilfield service companies such as drilling fluids companies, marine transportation companies and offshore construction companies.

The following is a summary description of our fifteen full service terminals:

Terminal	Location	Acres	Tanks	Aggregate Capacity
Pelican Island	Galveston, Texas	51.3	16	87,200 Bbls.
Harbor Island(1)	Harbor Island, Texas	25.5	12	32,500 Bbls.
Freeport	Freeport, Texas	17.8	1	8,300 Bbls.
Port O’Connor(2)	Port O’Connor, Texas	22.8	8	7,000 Bbls.
Sabine Pass(3)	Sabine Pass, Texas	23.1	11	17,000 Bbls.
Cameron “East”(4)	Cameron, Louisiana	34.3	12	34,000 Bbls.
Cameron “West”(5)	Cameron, Louisiana	16.9	5	16,500 Bbls.
Venice (6)	Venice, Louisiana	2.8	2	15,000 Bbls.
Theodore	Theodore, Alabama	14.0	18	19,800 Bbls.
Pascagoula	Pascagoula, Mississippi	29.0	5	11,400 Bbls.
Amelia-2 (7)(8)	Amelia, Louisiana	4.0	10	15,114 Bbls.
Cameron-7 (7)(9)	Cameron, Louisiana	8.0	1	15,000 Bbls.
Cameron-8 (7)(10)	Cameron, Louisiana	3.0	8	32,522 Bbls.
Intracoastal City-2 (7)(11)	Intracoastal City, Louisiana	10.0	15	24,334 Bbls.
Fourchon-15 (7)(12)	Fourchon, Louisiana	8.0	28	14,815 Bbls.

(1)

A portion of this terminal is located on land owned by a third party and leased under a lease that expires in January 2015.

(2) This terminal is located on land owned by a third party and leased under a lease that expires in March 2014.

(3) A portion of this terminal is located on land owned by a third party and leased under a lease that expires in September 2036.

(4) This terminal is located on land owned by third parties and leased under a lease that expires in March 2012 and can be extended by us through March 2022.

(5) This terminal is located on land owned by a third party and leased under a lease that expires in February 2013.

(6) This terminal is located on land owned by a third party and leased under a sublease agreement that expires in August 2012.

(7) These terminals were acquired from Martin Resource Management on January 31, 2011.

(8) This terminal is located on land owned by a third party and leased under a lease that expires in March 2012.

(9) This terminal is located on land owned by a third party and leased under a lease that expires in July 2012 and can be extended by us through July 2017.

(10) This terminal is located on land owned by a third party and leased under a lease that expires in July 2016 and can be extended by us through July 2036.

(11) This terminal is located on land owned by a third party and leased under a lease that expires in December 2015 and can be extended by us through December 2025.

(12) This terminal is located on land owned by a third party and leased under a lease that expires in December 2013 and can be extended by us through December 2033.

Fuel and Lubricant Terminals. We own or operate twelve lubricant and fuel oil terminals located in the Gulf Coast region that provide storage and handling services for lubricants and fuel oil.

The following is a summary description of our fuel and lubricant terminals:

Terminal	Location	Tanks	Aggregate Capacity
Amelia	Amelia, Louisiana	17	14,900 Bbls.
Berwick(1)	Berwick, Louisiana	2	25,000 Bbls.
Intracoastal City(2)(3)	Intracoastal City, Louisiana	16	39,000 Bbls.
Fourchon(4)	Fourchon, Louisiana	11	80,000 Bbls.
Cameron 6(5)(6)	Cameron, Louisiana	16	44,133 Bbls.
Dulac(5)(7)	Dulac, Louisiana	7	15,807 Bbls.
Fourchon 17(5)(8)	Fourchon, Louisiana	6	41,200 Bbls.
River Ridge (5)(9)	River Ridge, Louisiana	33	10,210 Bbls.
Morgan City DWC 31(5)(10)	Morgan City, Louisiana	37	27,176 Bbls.
Morgan City 33(5)(11)	Morgan City, Louisiana	10	53,579 Bbls.
Fourchon 16(5)(12)	Fourchon, Louisiana	16	13,318 Bbls.
Venice 2(5)(13)	Venice, Louisiana	16	29,520 Bbls.

____

(1) This terminal is located on land owned by third parties and leased under a lease that expires in September 2012 and can be extended by us through September 2017.

(2) A portion of this terminal is located on land owned by a third party at which we throughput fuel oil pursuant to an agreement that expired in January 2010 and is automatically renewed on a monthly basis.

(3) A portion of this terminal is located on land owned by third parties and leased under a lease that expires in April 2014.

(4) This terminal is located on land owned by a third party at which we throughput lubricants and fuel oil pursuant to an agreement that expires in January 2017.

(5) These terminals were acquired from Martin Resource Management on January 31, 2011.

(6) This terminal is located on land owned by third parties and leased under a lease that expires in March 2013 and can be extended by us through March 2013.

(7) This terminal is located on land owned by third parties and leased under a lease that expires in December 2012.

(8) This terminal is located on land owned by third parties and leased under a lease that expires in December 2013 and can be extended by us through December 2033.

(9) This terminal is located on land owned by third parties and leased under a lease that expires in April 2019.

(10) This terminal is located on land owned by third parties and leased under a lease that expires in December 2014 and can be extended by us through December 2034.

(11) This terminal is located on land owned by third parties and leased under a lease that expires in May 2014 and can be extended by us through May 2019.

(12) This terminal is located on land owned by third parties and leased under multiple leases that expires in July 2011, March 2012, and July 2012. These leases can be extended by us through July 2026, March 2022, and July 2022, respectively.

(13) This terminal is located on land owned by third parties and leased under a lease that expires in December 2012 and can be extended by us through December 2027.

Specialty Petroleum Terminals. We own or operate 12 terminal facilities providing storage and handling services for some or all of the following: anhydrous ammonia, asphalt, sulfur, sulfuric acid, fuel oil, crude oil and other petroleum products and by-products. Of our 12 terminals, one was acquired on January 31, 2011 through our acquisition of certain terminalling assets from Martin Resource Management. Our specialty terminals have an aggregate storage capacity of approximately 2.53 million barrels. Each of these terminals has storage capacity for petroleum products and by-products and has assets to handle products transported by vessel, barge and truck. The location and composition of our terminals are structured to complement our other businesses and reflect our strategy to provide a broad range of integrated services in the handling and transportation of petroleum products and by-products. We developed our terminalling and storage assets by acquiring existing terminalling and storage facilities and then customizing and upgrading these facilities as needed to integrate the facilities into our petroleum product and by-product transportation network and to more effectively service customers. We expect to continue to acquire facilities, streamline their operations and customize and upgrade them as part of our growth strategy. We also continually evaluate opportunities to add services and increase access to our terminals to attract more customers and create additional revenues.

Our Tampa terminal is located on approximately 10 acres of land owned by the Tampa Port Authority that was leased to us under a 10-year lease that commenced on December 16, 2006 with two five-year options. Our Stanolind terminal is located on approximately 11 acres of land owned by us located on the Neches River in Beaumont. Our Neches terminal is a deep water marine terminal located near Beaumont, Texas on approximately 50 acres of land owned by us. Our Ouachita County terminal is located on approximately six acres of land owned by us on the Ouachita River in southern Arkansas. Our Corpus Christi terminal is located on approximately 25 acres of land owned by us and has access to the waterfront via marine docks owned by the Port of Corpus Christi.

Table of Contents

At our Tampa, Neches, Stanolind and Corpus Christi terminals, our customers are primarily large oil refining and natural gas processing companies. We charge either a fixed monthly fee or a throughput fee for the use of our facilities, based on the capacity of the applicable tank. We conduct a substantial portion of our terminalling and storage operations under long-term contracts, which enhances the stability and predictability of our operations and cash flow. We attempt to balance our short-term and long-term terminalling contracts in order to allow us to maintain a consistent level of cash flow while maintaining flexibility to earn higher storage revenues when demand for storage space increases. In addition, a significant portion of the contracts for our specialty terminals provide for minimum fee arrangements that are not based on the volume handled. At our Ouachita County terminal, Cross Oil Refining & Marketing, Inc., a related party owned by Martin Resource Management, operates the terminal under a long-term terminalling agreement whereby we receive a throughput fee.

In Channelview, Texas, we operate a terminal used for lubricant blending, storage, packaging and distribution. This terminal is used as our central hub for lubricant distribution where we receive, package and ship our lubricants to our terminals or directly to customers.

In Smackover, Arkansas, we own a refining terminal where we process crude oil into finished products, including naphthenic lubricants, distillates, asphalt and other intermediate cuts. This process is dedicated to an affiliate of Martin Resource Management through a long-term tolling agreement based upon throughput rates and a monthly reservation fee.

In Houston, Texas, we own an asphalt terminal whose use is dedicated to an affiliate of Martin Resource Management through a terminalling service agreement based on throughput rates.

In Port Neches, Texas, we own an asphalt terminal whose use is dedicated to an affiliate of Martin Resource Management through a terminalling service agreement based upon throughput rates.

In Omaha, Nebraska, we own an asphalt terminal whose use is dedicated to an affiliate of Martin Resource Management through a terminalling service agreement based on throughput rates.

In Beaumont, Texas we own Spindletop Terminal where we receive natural gasoline via pipeline and then ship the product to our customers via other pipelines to which the facility is connected. Our fees for the use of this facility are based on the number of barrels shipped from the terminal.

In Lake Charles, Louisiana, we own a lubricant terminal on leased land whose use is dedicated to an affiliate of Martin Resource Management through a terminalling service agreement based on throughput rates.

We also continually evaluate opportunities to add services and increase access to our terminals to attract more customers and create additional revenues. The following is a summary description of our specialty marine terminals:

Terminal	Location	Tanks	Aggregate Capacity	Products	Description
Tampa(1)	Tampa, Florida	8	716,000 Bbls.	Asphalt, sulfur and fuel oil	Marine terminal, loading/unloading for vessels, barges railcars and trucks
Stanolind	Beaumont, Texas	9	555,000 Bbls.	Asphalt, crude oil, sulfur, sulfuric acid and fuel oil	Marine terminal, marine dock for loading/unloading of vessels, barges, railcars

					and trucks
Neches	Beaumont, Texas	8	500,000 Bbls.	Ammonia, asphalt, fuel oil, crude oil and sulfur-based fertilizer	Marine terminal, loading/unloading for vessels, barges, railcars and trucks
Ouachita County	Ouachita County, Arkansas	2	77,500 Bbls.	Crude oil	Marine terminal, loading/unloading for barges and trucks
Corpus Christi	Corpus Christi, Texas	4	330,000 Bbls.	Fuel oil and diesel	Marine Terminal, loading/unloading barges and vessels and unloading trucks

Table of Contents

Terminal	Location	Aggregate Capacity	Products	Description
Channelview	Houston, Texas	44,000 sq. ft. Warehouse 34,000 Bbls	Lubricants	Lubricants blending and storage
Cross Refining	Smackover, Arkansas	7,500 Bbls per day	Naphthenic lubricants, Distillates, Asphalt	Crude refining facility
South Houston Asphalt	Houston, Texas	71,000 Bbls	Asphalt	Asphalt Processing and storage
Port Neches Asphalt	Port Neches, Texas	31,250 Bbls	Asphalt	Asphalt Processing and storage
Omaha Asphalt	Omaha, Nebraska	114,225 Bbls	Asphalt	Asphalt Processing and storage
Spindletop	Beaumont, Texas	90,000 Bbls	Natural Gasoline	Pipeline receipts and shipments
Lake Charles (2)	Lake Charles, Louisiana	18,000 sq. ft.Warehouse 8,709 Bbls	Lubricants	Lubricants storage

(1) This terminal is located on land owned by the Tampa Port Authority that was leased to us under a 10-year lease that expires in December 2016 with two five-year extension options.

(2) This terminal is located on land owned by third parties and leased under a lease that expires in January 2016 and can be extended by us through January 2021. This terminal was acquired from Martin Resource Management on January 31, 2011.

Competition. We compete with independent terminal operators and major energy and chemical companies that own their own terminalling and storage facilities. We believe many customers prefer to contract with independent terminal operators rather than terminal operators owned by integrated energy and chemical companies that may have refining or marketing interests that compete with the customers.

Independent terminal owners generally compete on the basis of the location and versatility of terminals, service and price. A favorably-located terminal has access to various cost effective transportation modes, both to and from the terminal, such as waterways, railroads, roadways and pipelines. Terminal versatility depends upon the operator's ability to handle diverse products, some of which have complex or specialized handling and storage requirements. The service function of a terminal includes, among other things, the safe storage of product at specified temperature, moisture and other conditions, and receiving and delivering product to and from the terminal. All of these services must be in compliance with applicable environmental and other regulations.

We believe we successfully compete for terminal customers because of the strategic location of our terminals along the Gulf Coast, our integrated transportation services, our reputation, the prices we charge for our services and the quality and versatility of our services. Additionally, while some companies have significantly more terminalling and storage capacity than us, not all terminalling and storage facilities located in the markets we serve are equipped to properly handle specialty products such as asphalt, sulfur, anhydrous ammonia and sulfuric acid. As a result, our facilities typically command higher terminal fees when compared to fees charged for terminalling and storage of other petroleum products.

The principal competitive factors affecting our terminals which provide lubricant distribution and marketing, as well as shore bases at certain terminals, are the locations of the facilities, availability of competing logistical support services and the experience of personnel and dependability of service. The distribution and marketing of our lubricant products is brand sensitive and we encounter brand loyalty competition. Shore base rental contracts are generally long-term contracts and provide more protection from competition. Our primary competitors for both lubricants and shore bases include several independent operations as well as major companies that maintain their own similarly equipped marine terminals, shore bases and lubricant supply sources.

Natural Gas Services Segment

NGL Industry Overview. NGLs are produced through natural gas processing. They are also a by-product of crude oil refining. NGLs consists of hydrocarbons that are vapors at atmospheric temperatures and pressures but change to liquid phase under pressure. NGLs include ethane, propane, normal butane, iso butane and natural gasoline.

Table of Contents

Ethane is almost entirely used as a petrochemical feedstock in the production of ethylene and propylene. Propane is used as a petrochemical feedstock in the production of ethylene and propylene, as a fuel for heating, for industrial applications, as motor fuel and as a refrigerant. Normal butane is used as a petrochemical feedstock, as a blend stock for motor gasoline and as a component in aerosol propellants. Normal butane can also be made into iso butane through isomerization. Iso butane is used in the production of motor gasoline, alkylation or MTBE and as a component in aerosol propellants. Natural gasoline is used as a component of motor gasoline and as a petrochemical feedstock.

NGL Facilities. We purchase NGLs primarily from natural gas processors and, to a lesser extent, major domestic oil refiners. We transport NGLs using Martin Resource Management's land transportation fleet or by contracting with common carriers, owner-operators and railroad tank cars. We typically enter into annual contracts with independent retail propane distributors to deliver their estimated annual volume requirements based on prevailing market prices. We believe dependable delivery is very important to these customers and in some cases may be more important than price. We ensure adequate supply of NGLs through:

- storage of NGLs purchased in off-peak months;
- efficient use of the transportation fleet of vehicles owned by Martin Resource Management; and
- product management expertise to obtain supplies when needed.

The following is a summary description of our owned and leased NGL facilities:

NGL Facility	Location	Capacity	Description
Wholesale terminals	Arcadia, Louisiana(1)	2,400,000 barrels	Underground storage
	Hattiesburg, Mississippi(2)	100,000 barrels	Underground storage
	Mt. Belvieu, Texas(3)(2)	70,000 barrels	Underground storage
Retail terminals	Kilgore, Texas	90,000 gallons	Retail propane distribution
	Longview, Texas	30,000 gallons	Retail propane distribution
	Henderson, Texas	12,000 gallons	Retail propane distribution

(1) We lease our underground storage at Arcadia, Louisiana from Martin Resource Management under a three-year product storage agreement, which is renewable on a yearly basis thereafter subject to a re-determination of the lease rate for each subsequent year.
(2) We lease our underground storage at Hattiesburg, Mississippi and Mont Belvieu, Texas from third parties under one-year lease agreements, which have been renewed annually for more than 20 years.
(3) In addition, under a throughput agreement, we are entitled to the access and use of a truck loading and unloading and pipeline distribution terminal owned by Enterprise Products and located at Mont Belvieu, Texas. Effective each January 1, this agreement automatically renews for consecutive one-year periods unless either party terminates the agreement by giving written notice to the other party at least 30 days prior to the expiration of the then-applicable term. This terminal facility has a storage capacity of 8,000 barrels.

Our NGL customers that utilize these assets consist of retail propane distributors, industrial processors and refiners. For the year ended December 31, 2010, we sold approximately 35% of our NGL volume to independent retail propane distributors located in Texas and the southeastern United States and approximately 65% of our NGL volume to refiners and industrial processors.

NGL Competition. We compete with large integrated NGL producers and marketers, as well as small local independent marketers. NGLs compete primarily with natural gas, electricity and fuel oil as an energy source, principally on the basis of price, availability and portability.

NGL Seasonality. The level of NGL supply and demand is subject to changes in domestic production, weather, inventory levels and other factors. While production is not seasonal, residential and wholesale demand is highly seasonal. This imbalance causes increases in inventories during summer months when consumption is low and decreases in inventories during winter months when consumption is high. If inventories are low at the start of the winter, higher prices are more likely to occur during the winter. Additionally, abnormally cold weather can put extra upward pressure on prices during the winter because there are less readily available sources of additional supply except for imports which are less accessible and may take several weeks to arrive. General economic conditions and inventory levels have a greater impact on industrial and refinery use of NGLs than the weather.

Table of Contents

We generally maintain consistent margins in our natural gas services business because we attempt to pass increases and decreases in the cost of NGLs directly to our customers. We generally try to coordinate our sales and purchases of NGLs based on the same daily price index of NGLs in order to decrease the impact of NGL price volatility on our profitability.

Prism Gas. Prism Gas is operated and reported as part of our natural gas services business segment, which has been expanded to include natural gas gathering and processing as well as the NGL services business described herein.

Prism Gas has ownership interests in over 706 miles of gathering pipelines located in the natural gas producing regions of North Central Texas and East Texas, Northwest Louisiana, the Texas Gulf Coast and offshore Texas and federal waters in the Gulf of Mexico as well as a 285 MMcfd natural gas processing plant located in East Texas. The underlying assets are in two operating areas:

East Texas and North Central Texas

The East Texas and North Central Texas area assets consist of the Waskom Processing Plant, Harrison Pipeline System, East Harrison Gathering System, the Marshall Line, Woodlawn, the Prism Liquids Pipeline, the McLeod Gathering System, the Hallsville Gathering System, the Darco Gathering System and the East Texas Gathering systems. The East Texas Gathering systems were sold effective November 1, 2010.

- Waskom Processing Plant — The Waskom Processing Plant, located in Harrison County in East Texas, currently has 285 MMcfd of processing capacity with full fractionation facilities. Expansions to the processing plant were completed in March and June of 2007, July of 2008 and June of 2009 increasing the capacity from 150 MMcfd to 285 MMcfd. An additional expansion is anticipated and currently scheduled to be complete in the fourth quarter of 2011 which will increase the capacity to 320 MMcfd. In June 2009, the Waskom fractionator was expanded to a capacity of 14,500 barrels per day (“bpd”). For the years ended December 31, 2010 and 2009, inlet throughput and NGL fractionation averaged approximately 281 and 243 MMcfd and 9,691 and 10,034 bpd, respectively. Prism Gas owns an unconsolidated 50% operating interest in the Waskom Processing Plant with CenterPoint Energy Gas Processing, Inc. owning the remaining 50% non-operating interest. We reflect the results of operations from this facility using the equity method of accounting.

- Harrison Pipeline System – In January of 2010, as 50% owner and operator of Waskom Gas Processing Company, through Waskom Gas Processing Company’s wholly owned subsidiary Waskom Midstream LLC, we acquired the Harrison Pipeline System, located in Harrison County in East Texas. The system consisted of gathering pipeline, two 35 MMcfd dew point control plants and various equipment. In March of 2010 the gas was rerouted to the Waskom Processing Plant which resulted in the shutdown of the two dew point control plants. This allowed for the sale of one of the plants in 2010 with the expectation of the second plant being sold in the second quarter of 2011. For the year ended December 31, 2010, the system gathered 37 MMcfd. We reflect the results of operations from this system using the equity method of accounting.

- East Harrison Gathering System – The East Harrison Gathering System located in Harrison County in East Texas was acquired in December of 2009. Prism Gas owns a consolidated 100% interest in this system but leased the system to Waskom Midstream LLC effective March 1, 2010 and as such we reflect the results of operations using the equity method of accounting. For 2010, volumes transported through the system are included in the Harrison Pipeline System volumes.

- The Marshall Line — The Marshall Line is a 10” gathering line that Prism Gas began leasing from Kinder Morgan Texas in 2006. It is located in Harrison County in East Texas. The Marshall Line gathers gas at intermediate pressure and feeds the Waskom Processing Plant. Prism Gas owns a consolidated 100% interest in the lease which was assigned to Waskom Midstream LLC effective March 1, 2010 and as such we reflect the results of operations using the equity method of accounting. For 2010, volumes gathered on the Marshall Line are included in the Harrison Pipeline System volumes.

- Woodlawn Plant and Gathering System —Woodlawn is a natural gas gathering and processing company which owns integrated gathering and processing assets in East Texas. Woodlawn's system consists of natural gas gathering pipe, a condensate transport pipeline and a 30 MMcfd processing plant. For the years ended December 31, 2010 and 2009, the Woodlawn Gathering System gathered approximately 25 and 24 MMcfd of natural gas, respectively. Prism owns a consolidated 100% interest in this system.

Table of Contents

- The Prism Liquids Pipeline — The Prism Liquids Pipeline condensate system was formed from the condensate transport pipe obtained in the Woodlawn acquisition. The system was subsequently extended approximately 10 miles using lateral lines to gather condensate from additional locations. The pipeline is a common carrier under the Rules and Regulations of the Railroad Commission of Texas, Oil and Gas Division and, as such, operates under a tariff filed with the Railroad Commission of Texas. The system gathers and transports condensate for producers along the main line which extends south from the Woodlawn Plant to the Carthage Plant operated by DCP Midstream. For the years ended December 31, 2010 and 2009, the Prism Liquids Pipeline transported 1,278 and 2,190 bpd of condensate, respectively. Prism owns a consolidated 100% interest in this system.

- McLeod Gathering System — The McLeod Gathering System, located in East Texas and Northwest Louisiana, is a low-pressure gathering system connected to the Waskom Processing Plant providing processing and blending services for natural gas, with high nitrogen and high liquids content gathered by the system. For the years ended December 31, 2010 and 2009, the McLeod Gathering System gathered approximately 5 and 4 MMcfd of natural gas, respectively. Prism Gas owns a consolidated 100% interest in this system.

- Hallsville Gathering System — The Hallsville Gathering System, located in Harrison County, Texas, provides gathering and centralized compression for producers in the Oak Hill Field of East Texas. The system operates at low pressure and redelivers gas to two interstate and three intrastate markets via the Oakhill Gathering System. For the years ended December 31, 2010 and 2009, the Hallsville Gathering System gathered approximately 13 and 18 MMcfd of natural gas, respectively. Prism Gas owns a consolidated 100% interest in this system.

- Darco Gathering System — The Darco Gathering System located in Harrison County, Texas was acquired on November 1, 2010. The system consists of natural gas gathering pipe, various equipment and intangibles. The gathering system is tied to the Harrison Pipeline System and to a third party system. Prism Gas owns a consolidated 100% interest in this system. For November and December 2010, the Darco Gathering System gathered approximately 28 MMcfd of natural gas.

- East Texas Gathering System — The East Texas Gathering System, located in Panola County, Texas, is comprised of gathering systems built to gather gas produced in this area to market outlets. Prism Gas sold its 100% interest in these systems effective November 1, 2010.

The natural gas supply for the Waskom Processing Plant, the Harrison Pipeline System, the East Harrison Gathering system, the Marshall Line, the Woodlawn Plant and Gathering System, the McLeod Gathering System, the Hallsville Gathering System and the Darco Gathering System is derived primarily from natural gas wells located in the Cotton Valley and Haynesville formations of East Texas and Northwest Louisiana.

The Cotton Valley formation is one of the largest tight gas plays in the U.S. and extends over fourteen counties in East Texas and into Northwest Louisiana. Prism Gas' East Texas Operating Area includes assets that provide gathering and processing services to producers in Cass, Gregg, Harrison, Panola and Rusk Counties, Texas and Caddo Parish, Louisiana. The total number of wells permitted in Prism Gas' East Texas Operating Area was 934 and 419 in calendar years 2010 and 2009, respectively. These annual permit numbers include 363 and 200 permits for horizontal wells in 2010 and 2009, respectively. Improved technology and drilling applications have enhanced the economics of drilling in the Cotton Valley formation; however, in 2009 the economic benefit was more than offset by lower prices and as a result drilling activity declined. Due to the continuing weakness in natural gas prices, we anticipate that drilling activity in 2011 will stay above the low levels of 2009 but may not reach the 2010 levels.

In 2008, 2009 and 2010, development of the Haynesville Shale began. The Haynesville Shale is one of the four largest U.S. shale deposits. One of the largest producers in the Haynesville Shale estimates the formation will ultimately produce over 500 TCF of natural gas and will be among the top 10 natural gas fields in the world. Haynesville gas contains less natural gas liquids than Cotton Valley gas and as a result, in both 2010 and 2009, the inlet stream to Waskom Processing Plant contained less natural gas liquids than the historical average.

Our primary suppliers of natural gas to the Waskom Processing Plant include BP America Production Company, Centerpoint Energy Gas Transmission Company, Endeavour Pipeline, Inc., Samson Lone Star, LLC and Devon Energy Corporation, which collectively represented approximately 80% of the 281 MMcfd of natural gas supplied in 2010 and approximately 65% of the 243 MMcfd of natural gas supplied for the year ended December 31, 2009. A substantial portion (approximately 22%) of the Waskom Processing Plant's inlet volumes are derived from production at BP's Blocker, East Mountain, Carthage and Woodlawn fields in East Texas. Production from these fields is dedicated to the Waskom Processing Plant under a contract with BP for the life of the Waskom partnership. We receive natural gas at the Waskom Processing Plant from our McLeod Gathering System. We also receive a significant amount of trucked-in NGLs that are fractionated, treated and stabilized at the Waskom Processing Plant. In June 2009, we completed construction to expand the fractionator to 14,500 bpd to provide additional capacity for the increase in NGL volumes from the plant expansion that was underway and trucked-in NGL volumes. In 2010 and 2009, trucked-in NGL volumes decreased along with the decline in drilling activity. The processing plant was expanded to 285 MMcfd in four phases with the first expansion of 30 MMcfd being completed in March 2007, the second expansion of 70 MMcfd being completed in June 2007, the third phase of 15 MMcfd being completed in July 2008 and the fourth phase of 20 MMcfd being completed in June 2009. The fifth phase of 35 MMcfd is scheduled to be completed in the fourth quarter of 2011.

There are currently five cryogenic processing plants that compete with Waskom for natural gas supplies. Drilling activity in the Cotton Valley formation is moving north from the Panola-Harrison County line further into Harrison County. Our plant is the preferred gas plant for much of this new production due to its proximity to the increased drilling activity. In addition, the Waskom Processing Plant is the only plant in this area that has full fractionation capability with access to strong local markets for NGLs. Purchasers of NGLs fractionated at Waskom include various chemical companies and other industrial distributors.

The processing contracts for the Waskom Processing Plant are primarily percent-of-liquids ("POL") contracts, in which we retain a portion of the NGLs recovered as a processing fee, percent-of-proceeds ("POP") contracts in which we retain a portion of both the residue gas and the NGLs as payment for services and straight fee contracts in which we receive a fee for every Mcf of gas delivered to the plant. Currently, approximately 42% of the contracts are POL, 39% of the contracts are fee and 16% of the contracts are POP. In addition, there is one minor contract for processing on a keep-whole basis.

Woodlawn provides gathering and processing services. The Woodlawn gathering system provides both low and intermediate pressure gathering services. The gas is gathered to a 30 MMcfd refrigerated gas processing plant. The NGL's that are recovered at Woodlawn are trucked to the Waskom Processing Plant for fractionation. The contracts on the Woodlawn system are primarily wellhead purchase with some POP contracts.

The McLeod Gathering System is a low-pressure gathering system that provides an outlet for high nitrogen and high liquids content gas. In June 2003, Prism Gas constructed a pipeline to tie the McLeod Gathering System to the Waskom Processing Plant to provide an outlet for high nitrogen gas. As a result, the majority of gas gathered on the McLeod Gathering System is transported to the Waskom Processing Plant for processing and blending. Revenue from the McLeod Gathering System is earned through gathering and compression fees and processing revenue. The processing revenue results from the difference in the processing agreements with the producers and the agreement that we have with the Waskom partnership. The processing contracts in the McLeod Gathering System are predominately POP contracts. Natural gas gathered in the region surrounding the McLeod Gathering System has two primary outlets, including the Waskom Processing Plant.

Cotton Valley and Haynesville wells are now being drilled in the southern area served by the McLeod Gathering System. The new Cotton Valley wells that have recently been tied into the system are POL contracts with a small gathering fee. These contracts are typically lower margin, higher volume contracts. The Haynesville wells are typically fee based gathering. In this area, competition is geographic based with the McLeod Gathering System capturing wells that are located near the system and the competitor capturing wells that are near its system.

The Hallsville Gathering System was constructed in 2005 and 2006 to gather low pressure gas. The wells tied into the system are fee-based gathering contracts.

The Marshall Line was leased from Kinder Morgan to provide additional sources of gas for the Waskom Processing Plant. The gas on the system is from Cotton Valley production and is tied into the system under percent of index-based contracts.

Table of Contents

Gulf Coast

The Gulf Coast area assets consist of the Fishhook Gathering System and the Matagorda Offshore Gathering System ("Matagorda") located offshore and onshore of the Texas Gulf Coast.

- Fishhook Gathering System — The Fishhook Gathering System, located in Jefferson County, Texas offshore federal waters, gathers and transports gas in both offshore and onshore areas. In 2010, volumes were shut in on a significant portion of the system as a pipeline was rerouted in response to a producer platform removal. For the years ended December 31, 2010 and 2009 approximately 6 and 26 MMcfd of natural gas was gathered and transported on the system, respectively. Prism Gas owns an unconsolidated 50% non-operating interest in Panther Interstate Pipeline Energy, LLC ("PIPE"), the owner of the Fishhook Gathering System, with Panther Pipeline Ltd. owning the remaining 50% operating interest. We reflect the results of operations from this system using the equity method of accounting.

- Matagorda Offshore Gathering System — The Matagorda Offshore Gathering System, located in Matagorda County, Texas and offshore Texas State waters, gathers gas in both the offshore and onshore areas. For both years ended December 31, 2010 and 2009, the system gathered approximately 8 and 10 MMcfd of natural gas, respectively. Prism Gas owns an unconsolidated 50% non-operating interest in the Matagorda Offshore Gathering System, with Panther Pipeline Ltd. owning the remaining 50% operating interest. We reflect the results of operations from this system using the equity method of accounting.

The Fishhook Gathering System and the Matagorda Offshore Gathering System gather and transport natural gas from Texas and federal waters of the Gulf of Mexico to onshore pipelines. The Fishhook Pipeline gathers and transports natural gas principally from the eastern portion of the High Island Area which is further offshore. The offshore natural gas supply for the Matagorda Offshore Gathering System is produced primarily from the Brazos Area blocks, which are near shore in the Texas State waters. Additionally, the Matagorda Offshore Gathering System includes onshore gathering in Matagorda, Wharton and Brazoria Counties.

The Fishhook Gathering System is located in Jefferson County, Texas offshore federal waters and gathers gas from producers. Contracts on this system are 100% fee-for-service contracts with both the gathering fee and the maximum transmission fee stated in PIPE's FERC Gas Tariff, on file with the Federal Energy Regulatory Commission.

The Matagorda Offshore Gathering System gathers gas from producers. Contracts for the offshore portion of the Matagorda Offshore Gathering System are a combination of fixed transportation fees plus a fixed margin. The contracts for the onshore portion of the Matagorda Offshore Gathering System are under either a fixed margin or a fixed transportation fee. There is limited competition for the offshore portion of the pipeline. There are currently two pipelines situated in the offshore area but they primarily gather natural gas from wells further offshore than the Matagorda Offshore Gathering System. There are several pipelines that compete with the onshore portion of the system. These competing pipelines result in lower margins for the onshore portion of this system.

Sulfur Services Segment

Industry Overview. Sulfur is a natural element and is required to produce a variety of industrial products. In the United States, approximately 10 million tons of sulfur are consumed annually, with the Tampa, Florida area being the largest single market. Currently, all sulfur produced in the United States is "recovered sulfur," or sulfur that is a by-product from oil refineries and natural gas processing plants. Sulfur production in the United States is principally located along the Gulf Coast, along major inland waterways and in some areas of the western United States.

Sulfur is an important plant nutrient and is primarily used in the manufacture of phosphate fertilizers, with the balance used for industrial purposes. The primary application of sulfur in fertilizers occurs in the form of sulfuric acid. Burning sulfur creates sulfur dioxide, which is subsequently oxidized and dissolved in water to create sulfuric acid. The sulfuric acid is then combined with phosphate rock to make phosphoric acid, the base material for most high-grade phosphate fertilizers.

Sulfur-based fertilizers are manufactured chemicals containing nutrients known to improve the fertility of soils. Nitrogen, phosphorus, potassium and sulfur are the four most important nutrients for crop growth. These nutrients are found naturally in soils. However, soils used for agriculture become depleted of these nutrients and frequently require fertilizers rich in these essential nutrients to restore fertility.

Table of Contents

Industrial sulfur products (including sulfuric acid) are used in a wide variety of industries. For example, these products are used in power plants, paper mills, auto and tire manufacturing plants, food processing plants, road construction, cosmetics and pharmaceuticals.

Our Operations and Products. We have an integrated system of transportation assets and facilities relating to our sulfur services. We gather molten sulfur from refiners, primarily located on the Gulf Coast, and from natural gas processing plants, primarily located in the southwestern United States. We transport sulfur by inland and offshore barges, rail cars and trucks. In the U.S., recovered sulfur is mainly kept in liquid form from production to usage at a temperature of approximately 275 degrees Fahrenheit. Because of the temperature requirement, the sulfur industry uses specialized equipment to store and transport molten sulfur. We have the necessary transportation and storage assets and expertise to handle the unique requirements for transportation and storage of molten sulfur for domestic customers.

The terms of our commercial sulfur contracts typically range from one to five years in length. We handle molten sulfur on margin-based contracts. The prices in such contracts are usually tied to a published market indicator and fluctuate according to the price movement of the indicator. We also provide barge transportation and tank storage to large integrated oil companies that produce sulfur and fertilizer manufacturers that consume sulfur under transportation and storage contracts with remaining lives from one to two years in duration.

The sulfur prilling assets we acquired from the acquisition of Bay Sulfur in April 2005 are located at the Port of Stockton in California and are used to process molten sulfur into pellets. These dry, bulk pellets are stored and loaded at our facility at the Port of Stockton. The sulfur pellets are sold into certain U.S. and international agricultural markets. Our facility at the Port of Stockton can process approximately 1,000 metric tons of molten sulfur per day. In January 2007, we completed the construction of a sulfur priller at our Neches facility in Beaumont, Texas. In January 2009, we completed the construction of a second sulfur priller at our Neches facility in Beaumont, Texas. The two Beaumont prillers have the capacity to process approximately 4,000 metric tons of molten sulfur per day. We process molten sulfur into prilled sulfur on take-or-pay fee contracts. Our sulfur prilling facilities provide refiners access to the export market for the sale of their residual sulfur.

In late September 2007, we completed construction of a sulfuric acid production facility at our Plainview, Texas location. This facility processes molten sulfur to produce approximately 500 short tons of sulfuric acid per day. Our sulfuric acid facility provides our Plainview fertilizer plant with an economical supply of sulfuric acid and the remaining sulfuric production is sold to Martin Resource Management which markets the product to third parties.

We entered the sulfur based fertilizer manufacturing business in 1990 through an acquisition. We acquired two additional fertilizer manufacturing companies in 1998. Over the next two years we expended significant resources to replace and update facilities and other assets and to integrate each of the businesses into our business. These acquisitions have subsequently increased the profitability of our fertilizer business. In December 2005, sulfur fertilizer production capacity was added with the purchase of the net operating assets of A & A Fertilizer, Ltd. (“A & A Fertilizer”). This production capacity is located at our Neches deep-water marine terminal near Beaumont, Texas.

Fertilizer and related sulfur products are a natural extension of our molten sulfur business because of our access to sulfur and our distribution capabilities. These products allow us to leverage the sulfur services segment of our business. Our annual fertilizer and industrial sulfur products sales have grown from approximately 62,000 tons in 1997 to approximately 275,000 tons in 2010 as a result of acquisitions and internal growth.

In the United States, fertilizer is generally sold to farmers through local dealers. These dealers are typically owned and supplied by much larger wholesale distributors. We sell primarily to these wholesale distributors throughout the United States. Our industrial sulfur products are marketed primarily in the eastern United States, where many paper manufacturers and power plants are located. Our products are sold in accordance with price lists that vary from state to state. These price lists are updated periodically to reflect changes in seasonal or competitive prices. We transport our fertilizer and industrial sulfur products to our customers using third-party common carriers. We utilize rail shipments for large volume and long distance shipments where available.

We manufacture and market the following sulfur-based fertilizer and related sulfur products:

- Plant nutrient sulfur products. We produce plant nutrient and agricultural ground sulfur products at our two facilities in Odessa, Texas. We also produce plant nutrient sulfur at our facility in Seneca, Illinois. Our plant nutrient sulfur product is a 90% degradable sulfur product marketed under the Disper-Sul® trade name and sold throughout the United States to direct application agricultural markets. Our agricultural ground sulfur products are used primarily in the western United States on grapes and vegetable crops.

- Ammonium sulfate products, NPK products and related blended products. We produce various grades of ammonium sulfate including coarse and standard grades, a 40% ammonium sulfate solution and a Kosher-approved food grade material. We also produce nitrogen-phosphorus-potassium products (commonly referred to as NPK products). Our NPK products are an ammoniated phosphate fertilizer containing nitrogen, phosphorus and potash that we manufacture so all particles have a uniform composition. These products primarily serve direct application agricultural markets within a 400-mile radius of our manufacturing plant in Plainview, Texas. We blend our ammonium sulfate to make custom grades of lawn and garden fertilizer at our facility in Salt Lake City, Utah. We package these custom grade products under both proprietary and private labels and sell them to major retail distributors, and other retail customers, of these products.

Table of Contents

- Industrial sulfur products. We produce industrial sulfur products such as emulsified sulfur, elemental pastille sulfur, and industrial ground sulfur products. We produce emulsified sulfur at our Texarkana, Texas facility. Emulsified sulfur is primarily used to control the sulfur content in the pulp and paper manufacturing processes. We produce elemental pastille sulfur at our two Odessa, Texas facilities and at our Seneca, Illinois facility. Elemental pastille sulfur is used to increase the efficiency of the coal-fired precipitators in the power industry. These industrial ground sulfur products are also used in a variety of dusting and wettable sulfur applications such as rubber manufacturing, fungicides, sugar and animal feeds.

- Liquid sulfur products. We produce ammonium thiosulfate at our Neches terminal location in Beaumont, Texas. This agricultural sulfur product is a clear liquid containing 12% nitrogen and 26% sulfur. This product serves as a liquid plant nutrient used directly through spray rigs or irrigation systems. It is also blended with other NPK liquids or suspensions as well. Our market is predominantly the Mid South and Coastal Bend area of Texas.

Our Sulfur Services Facilities.

We own 58 railcars and lease approximately 140 railcars equipped to transport molten sulfur. We own the following major marine assets and use them to ship molten sulfur from our Beaumont, Texas terminal to our Tampa, Florida terminal:

Asset	Class of Equipment	Capacity/Horsepower	Products Transported
Margaret Sue	Offshore tank barge	10,450 long tons	Molten sulfur
M/V Martin Explorer	Offshore tugboat	7,200 horsepower	N/A
M/V Martin Express	Inland push boat	1,200 horsepower	N/A
MGM 101	Inland tank barge	2,450 long tons	Molten sulfur
MGM 102	Inland tank barge	2,450 long tons	Molten sulfur

We own the following sulfur prilling facilities as part of our sulfur services business:

Terminal	Location	Daily Production Capacity	Products Stored
Stockton	Stockton, California	1,000 metric tons per day	Molten and prilled sulfur
Neches	Beaumont, Texas	4,000 metric tons per day	Molten and prilled sulfur

We lease approximately 59 railcars to transport ammonium thiosulfate. We own the following manufacturing plants as part of our sulfur services business:

Facility	Location	Capacity	Description
Fertilizer plants (two)	Odessa, Texas	70,000 tons/year	Dry sulfur fertilizer production
Fertilizer plant	Seneca, Illinois	36,000 tons/year	Dry sulfur fertilizer production
Fertilizer plant	Plainview, Texas	180,000 tons/year	Fertilizer production
Fertilizer plant	Salt Lake City, Utah	25,000 tons/year	Blending and packaging
Fertilizer plant	Beaumont, Texas	70,000 tons/year	Liquid sulfur fertilizer production
Industrial sulfur plant	Texarkana, Texas	18,000 tons/year	Emulsified sulfur production

Sulfuric acid plant	Plainview Texas	150,000 tons/year	Sulfuric acid production

Competition. Seven phosphate fertilizer manufacturers together consume a vast majority of the total United States production of sulfur. These companies buy from resellers as well as directly from producers. We own one of the four vessels currently used to transport molten sulfur between United States ports on the Gulf of Mexico and Tampa, Florida. Our primary competition consists of producers that sell their production directly to a fertilizer manufacturer that has its own transportation assets or foreign suppliers from Mexico or Venezuela that may sell into the Florida market. Our sulfuric acid products compete with regional producers and importers in the South and Southwest portion of the U.S. from Louisiana to California. Our sulfur-based fertilizer products compete with several large fertilizer and sulfur products manufacturers. However, the close proximity of our manufacturing plants to our customer base is a competitive advantage for us in the markets we serve and allows us to minimize freight costs and respond quickly to customer requests.

Table of Contents

Seasonality. Sales of our agricultural fertilizer products are partly seasonal as a result of increased demand during the growing season.

Marine Transportation Segment

Industry Overview. The United States inland waterway system is a vast and heavily used transportation system. This inland waterway system is composed of a network of interconnected rivers and canals that serve as water highways and is used to transport vast quantities of products annually. This waterway system extends approximately 26,000 miles, of which 12,000 miles are generally considered significant for domestic commerce.

The Gulf Coast region is a major hub for petroleum refining. Approximately two-thirds of United States refining capacity expansion in the 1990s occurred in this region. The hydrocarbon refining process generates products and by-products that require transportation in large quantities from the refinery or processor. Convenient access to and use of this waterway system by the petroleum and petrochemical industry is a major reason for the current location of United States refineries and petrochemical facilities. Recent growth in refining and natural gas processing capacity has increased the volume of petroleum products and by-products transported within the Gulf Coast region, which consequently has increased the need for transportation, storage and distribution facilities.

The marine transportation industry uses push boats and tugboats as power sources and tank barges for freight capacity. The combination of the power source and tank barge freight capacity is called a tow.

Marine Fleet. We utilize a fleet of inland and offshore tows that provide marine transportation of petroleum products and by-products produced in oil refining and natural gas processing. Our marine transportation system operates coastwise along the Gulf of Mexico and on the United States inland waterway system, primarily between domestic ports along the Gulf of Mexico Intracoastal Waterway, the Mississippi River system and the Tennessee-Tombigbee Waterway system. Our inland tows generally consist of one push boat and one to three tank barges, depending upon the horsepower of the push boat, the river or canal capacity and conditions, and customer requirements. Each of our offshore tows consist of one tugboat, with much greater horsepower than an inland push boat, and one large tank barge.

We transport asphalt, fuel oil, gasoline, sulfur and other bulk liquids. The following is a summary description of the marine vessels we use in our marine transportation business:

Class of Equipment	Number in Class	Capacity/Horsepower	Description of Products Carried
Inland tank barges	13	20,000 bbl and under	Asphalt, crude oil, fuel oil, gasoline and sulfur
Inland tank barges	31	20,000 - 30,000 bbl	Asphalt, crude oil, fuel oil and gasoline
Inland push boats	18	800 - 3,800 horsepower	N/A
Offshore tank barges	5	40,000 bbl and 95,000 bbl	Asphalt, fuel oil and NGLs
Offshore tugboats	4		N/A

3,200 - 7,200 horsepower

Our largest marine transportation customers include major and independent oil and gas refining companies, petroleum marketing companies and Martin Resource Management. We conduct our marine transportation services on a fee basis primarily under annual contracts.

We are a party to a marine transportation agreement under which we provide marine transportation services to Martin Resource Management on a spot contract basis at applicable market rates. Effective each January 1, this agreement automatically renews for consecutive one-year periods unless either party terminates the agreement by giving written notice to the other party at least 60 days prior to the expiration of the then-applicable term. The fees we charge Martin Resource Management are based on applicable market rates.

Competition. We compete primarily with other marine transportation companies. The marine barging industry has experienced significant consolidation in the past few years. The total number of tank barges and push boats that operate in the inland waters of the United States declined from approximately 4,200 in 1982 and has reduced to approximately 3,100 by the end of 2009. We believe the earlier decrease primarily resulted from:

Table of Contents

- the increasing age of the domestic tank barge fleet, resulting in retirements;
- a reduction in tax incentives, which previously encouraged speculative construction of new equipment;
- stringent operating standards to adequately address safety and environmental risks;
- the elimination of government programs supporting small refineries;
- an increase in environmental regulations mandating expensive equipment modification; and
- more restrictive and expensive insurance.

There are several barriers to entry into the marine transportation industry that discourage the emergence of new competitors. Examples of these barriers to entry include:

- significant start-up capital requirements;
- the costs and operational difficulties of complying with stringent safety and environmental regulations;
- the cost and difficulty in obtaining insurance; and
- the number and expertise of personnel required to support marine fleet operations.

We believe the reduction of the number of tank barges, the consolidation among barging companies and the significant barriers to entry in the industry have resulted in a more stabilized and favorable pricing environment for our marine transportation services.

We believe we compete favorably with many of our competitors. Historically, competition within the marine transportation business was based primarily on price. However, we believe customers are placing an increased emphasis on safety, environmental compliance, quality of service and the availability of a single source of supply of a diversified package of services. In particular, we believe customers are increasingly seeking transportation vendors that can offer marine, land, rail and terminal distribution services, as well as provide operational flexibility, safety, environmental and financial responsibility, adequate insurance and quality of service consistent with the customer’s own operations and policies. We operate a diversified asset base that, together with the services provided by Martin Resource Management, enables us to offer our customers an integrated distribution network consisting of transportation, terminalling, distribution and midstream logistical services for petroleum products and by-products.

In addition to competitors that provide marine transportation services, we also compete with providers of other modes of transportation, such as rail tank cars, tractor-trailer tank trucks and, to a limited extent, pipelines. We believe we offer a competitive advantage over rail tank cars and tractor-trailer tank trucks because marine transportation is a more efficient, and generally less expensive, mode of transporting petroleum products and by-products. For example, a typical two inland barge unit carries a volume of product equal to approximately 80 rail cars or 250 tanker trucks. Pipelines generally provide a less expensive form of transportation than marine transportation. However, pipelines are not able to transport most of the products we transport and are generally a less flexible form of transportation because they are limited to the fixed point-to-point distribution of commodities in high volumes over extended periods of time.

Seasonality. The demand for our marine transportation business is subject to some seasonality factors. Our asphalt shipments are generally higher during April through November when weather allows for efficient road construction. However, demand for marine transportation of sulfur, fuel oil and gasoline is directly related to production of these products in the oil refining and natural gas processing business, which is fairly stable.

Our Relationship with Martin Resource Management

Martin Resource Management is engaged in the following principal business activities:

- providing land transportation of various liquids using a fleet of trucks and road vehicles and road trailers;

Table of Contents

- distributing fuel oil, asphalt, sulfuric acid, marine fuel and other liquids;
- providing marine bunkering and other shore-based marine services in Alabama, Louisiana, Mississippi and Texas;
- operating a small crude oil gathering business in Stephens, Arkansas;
- operating a lube oil packaging facility in Smackover, Arkansas;
- operating an underground NGL storage facility in Arcadia, Louisiana;
- building and marketing of sulfur processing equipments;
- developing an underground natural gas storage facilities in Arcadia, Louisiana and near Delhi, Louisiana;
- supplying employees and services for the operation of our business;
- operating, for its account and our account, the docks, roads, loading and unloading facilities and other common use facilities or access routes at our Stanolind terminal; and
- operating, solely for our account, the asphalt facilities in Omaha, Nebraska.

We are and will continue to be closely affiliated with Martin Resource Management as a result of the following relationships.

Ownership

As of March 2, 2011, Martin Resource Management owned an approximate 31.6% limited partnership interest and a 2% general partnership interest in us and all of our incentive distribution rights.

Management

Martin Resource Management directs our business operations through its ownership and control of our general partner. We benefit from our relationship with Martin Resource Management through access to a significant pool of management expertise and established relationships throughout the energy industry. We do not have employees. Martin Resource Management's employees are responsible for conducting our business and operating our assets on our behalf.

Related Party Agreements

We are a party to an omnibus agreement with Martin Resource Management. The omnibus agreement requires us to reimburse Martin Resource Management for all direct expenses it incurs or payments it makes on our behalf or in connection with the operation of our business. We reimbursed Martin Resource Management for $81.7 million, $63.1 and $67.5 million of direct costs and expenses for the twelve months ended December 31, 2010, 2009 and 2008, respectively. There is no monetary limitation on the amount we are required to reimburse Martin Resource Management for direct expenses.

In addition to the direct expenses, under the omnibus agreement, we are required to reimburse Martin Resource Management for indirect general and administrative and corporate overhead expenses. For the years ended December 31, 2010, 2009, and 2008, the Conflicts Committee of our general partner approved reimbursement amounts of $3.8,

$3.5, and $2.9 million, respectively, reflecting our allocable share of such expenses. The Conflicts Committee will review and approve future adjustments in the reimbursement amount for indirect expenses, if any, annually. These indirect expenses covered the centralized corporate functions Martin Resource Management provides for us, such as accounting, treasury, clerical billing, information technology, administration of insurance, general office expenses and employee benefit plans and other general corporate overhead functions we share with Martin Resource Management's retained businesses. The omnibus agreement also contains significant non-compete provisions and indemnity obligations. Martin Resource Management also licenses certain of its trademarks and trade names to us under the omnibus agreement.

In addition to the omnibus agreement, we and Martin Resource Management have entered into various other agreements that may not be the result of arm's-length negotiations and consequently may not be as favorable to us as they might have been if we had negotiated them with unaffiliated third parties. The agreements include, but are not limited to, a motor carrier agreement, a terminal services agreement, a marine transportation agreement, a product storage agreement, a product supply agreement, a throughput agreement, and a purchaser use easement, ingress-egress easement and utility facilities easement. Pursuant to the terms of the omnibus agreement, we are prohibited from entering into certain material agreements with Martin Resource Management without the approval of the Conflicts Committee of our general partner's board of directors.

Table of Contents

For a more comprehensive discussion concerning the omnibus agreement and the other agreements that we have entered into with Martin Resource Management, please see “Item 13. Certain Relationships and Related Transactions, and Director Independence – Agreements.”

Commercial

We have been and anticipate that we will continue to be both a significant customer and supplier of products and services offered by Martin Resource Management. Our motor carrier agreement with Martin Resource Management provides us with access to Martin Resource Management’s fleet of road vehicles and road trailers to provide land transportation in the areas served by Martin Resource Management. Our ability to utilize Martin Resource Management’s land transportation operations is currently a key component of our integrated distribution network.

We also use the underground storage facilities owned by Martin Resource Management in our natural gas services operations. We lease an underground storage facility from Martin Resource Management in Arcadia, Louisiana with a storage capacity of 2.4 million barrels. Our use of this storage facility gives us greater flexibility in our operations by allowing us to store a sufficient supply of product during times of decreased demand for use when demand increases.

In the aggregate, our purchases of land transportation services, NGL storage services, and lube oil product purchases and sulfur services payroll reimbursements from Martin Resource Management accounted for approximately 14%, 15% and 10% of our total cost of products sold during the years ended December 31, 2010, 2009, and 2008, respectively. We also purchase marine fuel from Martin Resource Management, which we account for as an operating expense.

Correspondingly, Martin Resource Management is one of our significant customers. It primarily uses our terminalling, marine transportation and NGL distribution services for its operations. We provide terminalling and storage services under a terminal services agreement. We provide marine transportation services to Martin Resource Management under a charter agreement on a spot-contract basis at applicable market rates. Our sales to Martin Resource Management accounted for approximately 10%, 7% and 6% of our total revenues for the years ended December 31, 2010, 2009 and 2008, respectively. We have entered into certain agreements with Martin Resource Management pursuant to which we provide terminalling and storage and marine transportation services to Midstream Fuel and Midstream Fuel provides terminal services to us to handle lubricants, greases and drilling fluids. Additionally, we have entered into a long-term, fee for services-based Tolling Agreement with Martin Resource Management where Martin Resource Management agrees to pay us for the processing of its crude oil into finished products, including naphthenic lubricants, distillates, asphalt and other intermediate cuts.

For a more comprehensive discussion concerning the omnibus agreement and the other agreements that we have entered into with Martin Resource Management, please see “Item 13. Certain Relationships and Related Transactions, and Director Independence – Agreements.”

Approval and Review of Related Party Transactions

If we contemplate entering into a transaction, other than a routine or in the ordinary course of business transaction, in which a related person will have a direct or indirect material interest, the proposed transaction is submitted for consideration to the board of directors of our general partner or to our management, as appropriate. If the board of directors is involved in the approval process, it determines whether to refer the matter to the Conflicts Committee of our general partner's board of directors, as constituted under our limited partnership agreement. If a matter is referred to the Conflicts Committee, it obtains information regarding the proposed transaction from management and determines whether to engage independent legal counsel or an independent financial advisor to advise the members of the committee regarding the transaction. If the Conflicts Committee retains such counsel or financial advisor, it considers such advice and, in the case of a financial advisor, such advisor's opinion as to whether the transaction is fair and reasonable to us and to our unitholders.

Insurance

Our deductible for onshore physical damage resulting from named windstorms is 5% of the total value located at an individual location subject to an overall minimum deductible of $2.5 million for all damage caused by the named windstorm. Our onshore program currently provides $30.0 million per occurrence for named windstorm events . For non-windstorm events, our deductible applicable to onshore physical damage remains at $0.5 million per occurrence. Business interruption coverage in connection with a windstorm event is subject to the same $30.0 Million per occurrence and aggregate limit as the property damage coverage and a waiting period of 45 days. For non-windstorm events, our waiting period applicable to business interruption is 30 days.

Loss of, or damage to, our vessels and cargo is insured through hull and cargo insurance policies. Vessel operating liabilities such as collision, cargo, environmental and personal injury are insured primarily through our participation in mutual insurance associations and other reinsurance arrangements, pursuant to which we are potentially exposed to assessments in the event claims by us or other members exceed available funds and reinsurance. Protection and indemnity, ("P&I"), insurance coverage is provided by P&I associations and other insurance underwriters. Our vessels are entered in P&I associations that are parties to a pooling agreement, known as the International Group Pooling Agreement, ("Pooling Agreement"), through which approximately 90% of the world's ocean-going tonnage is reinsured through a group reinsurance policy. With regard to collision coverage, the first $1.0 million of coverage is insured by our hull policy and any excess is insured by a P&I association. We insure our owned cargo through a domestic insurance company. We insure cargo owned by third parties through our P&I coverage. As a member of P&I associations that are parties to the Pooling Agreement, we are subject to supplemental calls payable to the associations of which we are a member, based on our claims record and the other members of the other P&I associations that are parties to the Pooling Agreement. Except for our marine operations, we self-insure against liability exposure up to a pre-determined amount, beyond which we are covered by catastrophe insurance coverage.

For marine pollution claims, our insurance covers up to $1.0 billion of liability per accident or occurrence and for non-pollution incidents, our insurance covers up to $2.0 billion of liability per accident or occurrence. We believe our current insurance coverage is adequate to protect us against most accident related risks involved in the conduct of our business and that we maintain appropriate levels of environmental damage and pollution insurance coverage. However, there can be no assurance that all risks are adequately insured against, that any particular claim will be paid by the insurer, or that we will be able to procure adequate insurance coverage at commercially reasonable rates in the future.

Environmental and Regulatory Matters

Our activities are subject to various federal, state and local laws and regulations, as well as orders of regulatory bodies, governing a wide variety of matters, including marketing, production, pricing, community right-to-know, protection of the environment, safety and other matters.

Environmental

We are subject to complex federal, state, and local environmental laws and regulations governing the discharge of materials into the environment or otherwise relating to protection of human health, natural resources and the environment. These laws and regulations can impair our operations that affect the environment in many ways, such as requiring the acquisition of permits to conduct regulated activities; restricting the manner in which we can release materials into the environment; requiring remedial activities or capital expenditures to mitigate pollution from former or current operations; and imposing substantial liabilities on us for pollution resulting from our operations. Many environmental laws and regulations can impose joint and several, strict liability, and any failure to comply with environmental laws and regulations may result in the assessment of administrative, civil, and criminal penalties, the imposition of investigatory and remedial obligations, and, in some circumstances, the issuance of injunctions that can limit or prohibit our operations.

The clear trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment, and, thus, any changes in environmental laws and regulations that result in more stringent and costly waste handling, storage, transport, disposal, or remediation requirements could have a material adverse effect on our operations and financial position. Moreover, there is inherent risk of incurring significant environmental costs and liabilities in the performance of our operations due to our handling of petroleum hydrocarbons, chemical substances, and wastes as well as the accidental release or spill of such materials into the environment. Consequently, we cannot assure you that we will not incur significant costs and liabilities as result of such handling practices, releases or spills, including those relating to claims for damage to property and persons. In the event of future increases in costs, we may be unable to pass on those increases to our customers. While we believe that we are in substantial compliance with current environmental laws and regulations and that continued compliance with existing requirements would not have a material adverse impact on us, we cannot provide any assurance that our environmental compliance expenditures will not have a material adverse impact on us in the future.

Superfund

The Federal Comprehensive Environmental Response, Compensation and Liability Act, as amended, ("CERCLA"), also known as the "Superfund" law, and similar state laws, impose liability without regard to fault or the legality of the original conduct, on certain classes of "responsible persons," including the owner or operator of a site where regulated hazardous substances have been released into the environment and companies that disposed or arranged for the disposal of the hazardous substances found at such site. Under CERCLA, these responsible persons may be subject to joint and several, strict liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources, and for the costs of certain health studies, and it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances into the environment. Although certain hydrocarbons are not subject to CERCLA's reach because "petroleum" is excluded from CERCLA's definition of a "hazardous substance," in the course of our ordinary operations we will generate wastes that may fall within the definition of a "hazardous substance." We have not received any notification that we may be potentially responsible for cleanup costs under CERCLA.

Solid Waste

We generate both hazardous and nonhazardous solid wastes which are subject to requirements of the federal Resource Conservation and Recovery Act, as amended ("RCRA") and comparable state statutes. From time to time, the U.S. Environmental Protection Agency ("EPA") has considered making changes in nonhazardous waste standards that would result in stricter disposal requirements for these wastes. Furthermore, it is possible some wastes generated by us that are currently classified as nonhazardous may in the future be designated as "hazardous wastes," resulting in the wastes being subject to more rigorous and costly disposal requirements. Changes in applicable regulations may result in an increase in our capital expenditures or operating expenses.

We currently own or lease, and have in the past owned or leased, properties that have been used for the manufacturing, processing, transportation and storage of petroleum products and by-products. Solid waste disposal practices within oil and gas related industries have improved over the years with the passage and implementation of various environmental laws and regulations. Nevertheless, a possibility exists that hydrocarbons and other solid wastes may have been disposed of on or under various properties owned or leased by us during the operating history of those facilities. In addition, a number of these properties have been operated by third parties over whom we had no control as to such entities' handling of hydrocarbons, hydrocarbon by-products or other wastes and the manner in which such substances may have been disposed of or released. State and federal laws and regulations applicable to oil and natural gas wastes and properties have gradually become more strict and, under such laws and regulations, we could be required to remove or remediate previously disposed wastes or property contamination, including groundwater contamination, even under circumstances where such contamination resulted from past operations of third parties.

Clean Air Act

Our operations are subject to the federal Clean Air Act, as amended, and comparable state statutes. Amendments to the Clean Air Act adopted in 1990 contain provisions that may result in the imposition of increasingly stringent pollution control requirements with respect to air emissions from the operations of our terminal facilities, processing and storage facilities and fertilizer and related products manufacturing and processing facilities. Such air pollution control requirements may include specific equipment or technologies to control emissions, permits with emissions and operational limitations, pre-approval of new or modified projects or facilities producing air emissions, and similar measures. For example, the Neches Terminal we use is located in an EPA-designated ozone non-attainment area, referred to as the Beaumont/Port Arthur non-attainment area, which is now subject to a new, EPA-adopted 8-hour standard for complying with the national standard for ozone. Categorized as being in "moderate" non-attainment for ozone, the Beaumont/Port Arthur non-attainment area has until 2010 to achieve compliance with this new standard, which almost certainly will require the adoption of more restrictive regulations in this non- attainment area for the issuance of air permits for new or modified facilities. In addition, existing sources of air emissions in the Beaumont/Port Arthur area are already subject to stringent emission reduction requirements. Failure to comply with applicable air statutes or regulations may lead to the assessment of administrative, civil or criminal penalties, and/or result in the limitation or cessation of construction or operation of certain air emission sources. We believe our operations, including our manufacturing, processing and storage facilities and terminals, are in substantial compliance with applicable requirements of the Clean Air Act and analogous state laws.

Global Warming and Climate Change. 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 warming of the Earth’s atmosphere. In response to such studies, the U.S. Congress is actively considering climate change-related legislation to restrict greenhouse gas emissions. At least 17 states have already taken legal measures to reduce emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. Also, as a result of the U.S. Supreme Court’s decision on April 2, 2007, in Massachusetts, et al. v. EPA, the EPA must consider whether it is required to regulate greenhouse gas emissions from mobile sources (e.g., cars and trucks) even if Congress does not adopt new legislation specifically addressing emissions of greenhouse gases. The Court's holding in Massachusetts that greenhouse gases fall under the federal Clean Air Act's definition of "air pollutant" may also result in future regulation of greenhouse gas emissions from stationary sources under various Clean Air Act programs. New legislation or regulatory programs that restrict emissions of greenhouse gases in areas in which we conduct business could adversely affect our operations and demand for our services.

Table of Contents

Clean Water Act

The Federal Water Pollution Control Act, as amended, also known as the Clean Water Act, and analogous state laws impose restrictions and controls on the discharge of pollutants into federal and state waters. Regulations promulgated under these laws require entities that discharge into federal and state waters obtain National Pollutant Discharge Elimination System ("NPDES") and/or state permits authorizing these discharges. The Clean Water Act and analogous state laws assess penalties for releases of unauthorized pollutants into the water and impose substantial liability for the costs of removing spills from such waters. In addition, the Clean Water Act and analogous state laws require that individual permits or coverage under general permits be obtained by covered facilities for discharges of storm water runoff and that applicable facilities develop and implement plans for the management of storm water runoff (referred to as storm water pollution prevention plans ("SWPPPs")) as well as for the prevention and control of oil spills (referred to as spill prevention, control and countermeasure ("SPCC") plans). As part of the regular overall evaluation of our on-going operations, we are reviewing and, as necessary, updating SWPPPs for certain of our facilities, including facilities recently acquired. In addition, we have reviewed our SPCC plans and, where necessary, amended such plans to comply with applicable regulations adopted by EPA in 2002. We believe that compliance with the conditions of such permits and plans will not have a material effect on our operations.

Oil Pollution Act

The Oil Pollution Act of 1990, as amended ("OPA") imposes a variety of regulations on "responsible parties" related to the prevention of oil spills and liability for damages resulting from such spills in United States waters. A "responsible party" includes the owner or operator of a facility or vessel, or the lessee or permittee of the area in which an offshore facility is located. The OPA assigns liability to each responsible party for oil removal costs and a variety of public and private damages including natural resource damages. Under OPA, vessels and shore facilities handling, storing, or transporting oil are required to develop and implement oil spill response plans, and vessels greater than 300 tons in weight must provide to the United States Coast Guard evidence of financial responsibility to cover the costs of cleaning up oil spills from such vessels. The OPA also requires that all newly constructed tank barges engaged in oil transportation in the United States be double hulled and all existing single hull tank barges be retrofitted with double hulls or phased out by 2015. We believe we are in substantial compliance with all of the oil spill-related and financial responsibility requirements.

Safety Regulation

The Company's marine transportation operations are subject to regulation by the United States Coast Guard, federal laws, state laws and certain international treaties. Tank ships, push boats, tugboats and barges are required to meet construction and repair standards established by the American Bureau of Shipping, a private organization, and the United States Coast Guard and to meet operational and safety standards presently established by the United States Coast Guard. We believe our marine operations and our terminals are in substantial compliance with current applicable safety requirements.

Occupational Health Regulations

The workplaces associated with our manufacturing, processing, terminal and storage facilities are subject to the requirements of the federal Occupational Safety and Health Act ("OSHA") and comparable state statutes. We believe we have conducted our operations in substantial compliance with OSHA requirements, including general industry standards, record keeping requirements and monitoring of occupational exposure to regulated substances. In May 2001, Martin Resource Management paid a small fine in relation to the settlement of alleged OSHA violations at our facility in Plainview, Texas. Although we believe the amount of this fine and the nature of these violations were not, as an individual event, material to our business or operations, this violation may result in increased fines and other sanctions if we are cited for similar violations in the future. Our marine vessel operations are also subject to safety and operational standards established and monitored by the United States Coast Guard.

Table of Contents

In general, we expect to increase our expenditures relating to compliance with likely higher industry and regulatory safety standards such as those described above. These expenditures cannot be accurately estimated at this time, but we do not expect them to have a material adverse effect on our business.

Jones Act

The Jones Act is a federal law that restricts maritime transportation between locations in the United States to vessels built and registered in the United States and owned and manned by United States citizens. Since we engage in maritime transportation between locations in the United States, we are subject to the provisions of the law. As a result, we are responsible for monitoring the ownership of our subsidiaries that engage in maritime transportation and for taking any remedial action necessary to insure that no violation of the Jones Act ownership restrictions occurs. The Jones Act also requires that all United States-flagged vessels be manned by United States citizens. Foreign-flagged seamen generally receive lower wages and benefits than those received by United States citizen seamen. This requirement significantly increases operating costs of United States-flagged vessel operations compared to foreign-flagged vessel operations. Certain foreign governments subsidize their nations' shipyards. This results in lower shipyard costs both for new vessels and repairs than those paid by United States-flagged vessel owners. The United States Coast Guard and American Bureau of Shipping maintain the most stringent regimen of vessel inspection in the world, which tends to result in higher regulatory compliance costs for United States-flagged operators than for owners of vessels registered under foreign flags of convenience. Following Hurricane Katrina, and again after Hurricane Rita, emergency suspensions of the Jones Act were effectuated by the United States government. The last suspension ended on October 24, 2005. Future suspensions of the Jones Act or other similar actions could adversely affect our cash flow and ability to make distributions to our unitholders.

Merchant Marine Act of 1936

The Merchant Marine Act of 1936 is a federal law that provides that, upon proclamation by the President of the United States of a national emergency or a threat to the national security, the United States Secretary of Transportation may requisition or purchase any vessel or other watercraft owned by United States' citizens (including us, provided that we are considered a United States citizen for this purpose). If one of our push boats, tugboats or tank barges were purchased or requisitioned by the United States government under this law, we would be entitled to be paid the fair market value of the vessel in the case of a purchase or, in the case of a requisition, the fair market value of charter hire. However, if one of our push boats or tugboats is requisitioned or purchased and its associated tank barge is left idle, we would not be entitled to receive any compensation for the lost revenues resulting from the idled barge. We also would not be entitled to be compensated for any consequential damages we suffer as a result of the requisition or purchase of any of our push boats, tugboats or tank barges.

Regulations Affecting Natural Gas Transmission, Processing and Gathering

We own a 50% non-operating interest in PIPE. PIPE's Fishhook Gathering System transports natural gas in interstate commerce and is thus subject to FERC regulations and FERC-approved tariffs as a natural gas company under the National Gas Act of 1938 ("NGA"). Under the NGA, FERC has issued orders requiring pipelines to provide open-access transportation on a basis that is equal for all shippers. In addition, FERC has the authority to regulate natural gas companies with respect to: rates, terms and conditions of service; the types of services PIPE may provide to its customers; the construction of new facilities; the acquisition, extension, expansion or abandonment of services or facilities; the maintenance and retention of accounts and records; and relationships of affiliated companies involved in all aspects of the natural gas and energy business.

On August 8, 2005, President George W. Bush signed into law the Domenici-Barton Energy Policy Act of 2005 ("EP Act"). The EP Act is a comprehensive compilation of tax incentives, authorized appropriations for grants and guaranteed loans, and significant changes to the statutory policy that affects all segments of the energy industry. With respect to regulation of natural gas transportation, the EP Act amends the NGA and the Natural Gas Policy Act of 1978 by increasing the criminal penalties available for violations of each act. The EP Act also adds a new section to the NGA which provides FERC with the power to assess civil penalties of up to $1,000,000 per day per violation of the NGA.

Additional proposals and proceedings that might affect the natural gas industry are pending before Congress, FERC and the courts. However, we do not believe that we will be disproportionately affected as compared to other natural gas producers and marketers by any action taken. We believe that our natural gas gathering operations meet the tests FERC uses to establish a pipeline’s status as a gatherer exempt from FERC regulation under the NGA, but FERC regulation still affects these businesses and the markets for products derived from these businesses. FERC’s policies and practices across the range of its oil and natural gas regulatory activities, including, for example, its policies on open access transportation, ratemaking, capacity release and market center promotion, indirectly affect intrastate markets. In recent years, FERC has pursued pro-competitive policies in its regulation of interstate oil and natural gas pipelines. However, we cannot assure our unitholders that FERC will continue this approach as it considers matters such as pipeline rates and rules and policies that may affect rights of access to oil and natural gas transportation capacity. In addition, the distinction between FERC-regulated transmission services and federally unregulated gathering services has been the subject of regular litigation, so, in such a circumstance, the classification and regulation of some of our gathering facilities and intrastate transportation pipelines may be subject to change based on future determinations by FERC and the courts.

Table of Contents

Other state and local regulations also affect our natural gas processing and gathering business. Our gathering lines are subject to ratable take and common purchaser statutes in Louisiana and Texas. Ratable take statutes generally require gatherers to take, without undue discrimination, oil or natural gas production that may be tendered to the gatherer for handling. Similarly, common purchaser statutes generally require gatherers to purchase without undue discrimination as to source of supply or producer. These statutes restrict our right as an owner of gathering facilities to decide with whom we contract to purchase or transport oil or natural gas. Federal law leaves any economic regulation of natural gas gathering to the states. The states in which we operate have adopted complaint-based regulation of oil and natural gas gathering activities, which allows oil and natural gas producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to oil and natural gas gathering access and rate discrimination. Other state regulations may not directly regulate our business, but may nonetheless affect the availability of natural gas for purchase, processing and sale, including state regulation of production rates and maximum daily production allowable from gas wells. While our gathering lines currently are subject to limited state regulation, there is a risk that state laws will be changed, which may give producers a stronger basis to challenge proprietary status of a line, or the rates, terms and conditions of a gathering line providing transportation service.

Pursuant to the Pipeline Safety Improvement Act of 2002, the United States Department of Transportation (“DOT”) has adopted regulations requiring pipeline operators to develop integrity management programs for transportation pipelines located where a leak or rupture could do the most harm in “high consequence areas.” The regulations require operators to:

- perform ongoing assessments of pipeline integrity;
- identify and characterize applicable threats to pipeline segments that could impact a high consequence area;
- improve data collection, integration and analysis;
- repair and remediate the pipeline as necessary; and
- implement preventive and mitigating actions.

Employees

We do not have any employees. Under our omnibus agreement with Martin Resource Management, Martin Resource Management provides us with corporate staff and support services. These services include centralized corporate functions, such as accounting, treasury, engineering, information technology, insurance, administration of employee benefit plans and other corporate services. Martin Resource Management employs approximately 647 individuals including 38 employees represented by labor unions who provide direct support to our operations as of March 2, 2011.

Financial Information about Segments

Information regarding our operating revenues and identifiable assets attributable to each of our segments is presented in Note 19 to our consolidated financial statements included in this annual report on Form 10-K.

Access to Public Filings

We provide public access to our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to these reports filed with the Securities and Exchange Commission (“SEC”) under the Securities and Exchange Act of 1934. These documents may be accessed free of charge on our website at the following address: www.martinmidstream.com. These documents are provided as soon as is reasonably practicable after their filing with the SEC. This website address is intended to be an inactive, textual reference only, and none of the material on this website is part of this report. These documents may also be found at the SEC's website at www.sec.gov.

Table of Contents

Item 1A. Risk Factors

Limited partner interests are inherently different from the capital stock of a corporation, although many of the business risks to which we are subject are similar to those that would be faced by a corporation engaged in a business similar to ours. If any of the following risks were actually to occur, our business, financial condition or results of operations could be materially adversely affected. In this case, we might not be able to pay distributions on our common units, the trading price of our common units could decline and unitholders could lose all or part of their investment. These risk factors should be read in conjunction with the other detailed information concerning us set forth herein.

Risks Relating to Our Business

Important factors that could cause actual results to differ materially from our expectations include, but are not limited to, the risks set forth below. The risks described below should not be considered to be comprehensive and all-inclusive. Many of such factors are beyond our ability to control or predict. Unitholders are cautioned not to put undue reliance on forward-looking statements. Additional risks that we do not yet know of or that we currently think are immaterial may also impair our business operations, financial condition and results of operations.

We may not have sufficient cash after the establishment of cash reserves and payment of our general partner's expenses to enable us to pay the minimum quarterly distribution each quarter.

We may not have sufficient available cash each quarter in the future to pay the minimum quarterly distribution on all our units. Under the terms of our partnership agreement, we must pay our general partner's expenses and set aside any cash reserve amounts before making a distribution to our unitholders. The amount of cash we can distribute on our common units principally depends upon the amount of net cash generated from our operations, which will fluctuate from quarter to quarter based on, among other things:

- the costs of acquisitions, if any;
- the prices of petroleum products and by-products;
- fluctuations in our working capital;
- the level of capital expenditures we make;
- restrictions contained in our debt instruments and our debt service requirements;
- our ability to make working capital borrowings under our credit facility; and
- the amount, if any, of cash reserves established by our general partner in its discretion.

Unitholders should also be aware that the amount of cash we have available for distribution depends primarily on our cash flow, including cash flow from working capital borrowings, and not solely on profitability, which will be affected by non-cash items. In addition, our general partner determines the amount and timing of asset purchases and sales, capital expenditures, borrowings, issuances of additional partnership securities and the establishment of reserves, each of which can affect the amount of cash available for distribution to our unitholders. As a result, we may make cash distributions during periods when we record losses and may not make cash distributions during periods when we record net income.

Restrictions in our credit facility may prevent us from making distributions to our unitholders.

The payment of principal and interest on our indebtedness reduces the cash available for distribution to our unitholders. In addition, we are prohibited by our credit facility from making cash distributions during a default or an event of default under our credit facility or if the payment of a distribution would cause a default or an event of default thereunder. Our leverage and various limitations in our credit facility may reduce our ability to incur additional debt, engage in certain transactions and capitalize on acquisition or other business opportunities that could increase cash flows and distributions to our unitholders.

Table of Contents

If we do not have sufficient capital resources for acquisitions or opportunities for expansion, our growth will be limited.

We intend to explore acquisition opportunities in order to expand our operations and increase our profitability. We may finance acquisitions through public and private financing, or we may use our limited partner interests for all or a portion of the consideration to be paid in acquisitions. Distributions of cash with respect to these equity securities or limited partner interests may reduce the amount of cash available for distribution to the common units. In addition, in the event our limited partner interests do not maintain a sufficient valuation, or potential acquisition candidates are unwilling to accept our limited partner interests as all or part of the consideration, we may be required to use our cash resources, if available, or rely on other financing arrangements to pursue acquisitions. If we use funds from operations, other cash resources or increased borrowings for an acquisition, the acquisition could adversely impact our ability to make our minimum quarterly distributions to our unitholders. Additionally, if we do not have sufficient capital resources or are not able to obtain financing on terms acceptable to us for acquisitions, our ability to implement our growth strategies may be adversely impacted.

We may not be able to obtain funding on acceptable terms or at all because of the deterioration of the credit and capital markets. This may hinder or prevent us from meeting our future capital needs.

Although the domestic capital markets have shown signs of improvement in recent months, global financial markets and economic conditions have been, and continue to be, disrupted and volatile due to a variety of factors, including uncertainty in the financial services sector, low consumer confidence, continued high unemployment, geopolitical issues and the current weak economic conditions. In addition, the fixed-income markets have experienced periods of extreme volatility, which have negatively impacted market liquidity conditions.

As a result of these conditions, the availability of funds from the credit and capital markets has diminished significantly, and the cost of raising money in the debt and equity capital markets has increased substantially. In particular, as a result of concerns about the stability of financial markets generally and the solvency of lending counterparties specifically, the cost of obtaining money from the credit markets may increase as many lenders and institutional investors increase interest rates, enact tighter lending standards, refuse to refinance existing debt on similar terms or at all and reduce, or in some cases cease to provide, funding to borrowers. In addition, lending counterparties under our existing revolving credit facility and other debt instruments may be unwilling or unable to meet their funding obligations. These conditions have made, and may continue to make, it difficult to obtain funding for our capital needs. Due to these conditions, we cannot be certain that new debt or equity financing will be available on acceptable terms or at all. If funding is not available when needed, or is available only on unfavorable terms, we may be unable to execute our growth strategy, meet our obligations as they come due or complete future acquisitions or expansion and maintenance capital projects, any of which could have a material adverse effect on our revenues and results of operations.

We are exposed to counterparty risk in our credit facility and related interest rate protection agreements.

We rely on our credit facility to assist in financing a significant portion of our working capital, acquisitions and capital expenditures. Our ability to borrow under our credit facility may be impaired because:

- one or more of our lenders may be unable or otherwise fail to meet its funding obligations;
- the lenders do not have to provide funding if there is a default under the credit facility or if any of the representations or warranties included in the credit facility are false in any material respect; and
-

if any lender refuses to fund its commitment for any reason, whether or not valid, the other lenders are not required to provide additional funding to make up for the unfunded portion.

If we are unable to access funds under our credit facility, we will need to meet our capital requirements, including some of our short-term capital requirements, using other sources. Alternative sources of liquidity may not be available on acceptable terms, if at all. If the cash generated from our operations or the funds we are able to obtain under our credit facility or other sources of liquidity are not sufficient to meet our capital requirements, then we may need to delay or abandon capital projects or other business opportunities, which could have a material adverse effect on our business, financial condition and results of operations.

In addition, we have entered into interest rate protection agreements to manage our interest rate risk exposure by fixing a portion of the interest expense we pay on our long-term debt under our credit facility. There is considerable turmoil in the world economy and banking markets, which could affect whether the counterparties to such interest rate protection agreements are able to honor their agreements. If the counterparties fail to honor their commitments, we could experience higher interest rates, which could have a material adverse effect on our business, financial condition and results of operations. In addition, if the counterparties fail to honor their commitments, we also may be required to replace such interest rate protection agreements with new interest rate protection agreements, and such replacement interest rate protection agreements may be at higher rates than our current interest rate protection agreements, which could have a material adverse effect on our business, financial condition and results of operations.

Current economic conditions may significantly affect our customers and their ability to make payments to us.

Since 2008, economic conditions in the United States have experienced a downturn due to the sequential effects of the sub-prime lending crisis, general credit market crisis, the general unavailability of financing, collateral effects on the finance and banking industries, volatile energy prices, concerns about inflation, slower economic activity, decreased consumer confidence, reduced corporate profits and capital spending, adverse business conditions, increased unemployment, liquidity concerns and declines in housing prices and house sales. How long these conditions will continue is unclear.

Uncertainty about current economic conditions may adversely affect our customers' abilities to make payments to us when due. As such, we could see an increase in delayed or uncollected receivables, which may have an adverse effect on our results of operations, cash flow and ability to make distributions to our unitholders.

The impacts of climate-related initiatives at the international, federal and state levels remain uncertain at this time.

Currently, there are numerous international, federal and state-level initiatives and proposals addressing domestic and global climate issues. Within the U.S., most of these proposals would regulate and/or tax, in one fashion or another, the production of carbon dioxide and other "greenhouse gases" to facilitate the reduction of carbon-compound emissions to the atmosphere, and provide tax and other incentives to produce and use more "clean energy." These include requirements that became effective January 2010 that require petroleum and natural gas facilities that emit more than 25,000 metric tons of carbon dioxide equivalents per year to report their annual emissions of greenhouse gases to the EPA beginning in 2011. In late 2010, the EPA finalized a rule requiring new and modified facilities that will emit greenhouse gases in excess of certain thresholds to obtain construction permits that address their greenhouse gas emissions. In addition, proposed federal, state and regional initiatives could require us to reduce greenhouse gas emissions from our existing facilities. Requirements to reduce greenhouse gas emissions could cause us to incur substantial costs to (i) operate and maintain our facilities, (ii) install new emission controls at our facilities and (iii) administer and manage any greenhouse gas emissions programs, including the acquisition or maintenance of emission credits or allowances. More broadly, mandates to reduce greenhouse gas emissions and to increase use of renewable fuels could decrease demand for hydrocarbon-based products and energy, which could have an indirect, but material, adverse effect on our business, financial condition and results of operations.

It is expected that climate change legislation will continue to be part of the legislative and regulatory discussion for the foreseeable future. Increased regulation of emissions, especially in the transportation sector, could impose significant additional costs on us and our customers. The impact of legislation and regulations on us will depend on a number of factors, including (i) what industry sectors would be impacted, (ii) the timing of required compliance, (iii) the overall emissions cap level, (iv) the allocation of emission allowances to specific sources, and (v) the costs and opportunities associated with compliance. At this time, we cannot predict the effect that climate change regulation may have on our business, financial condition or results of operations in the future.

Our recent and future acquisitions may not be successful, may substantially increase our indebtedness and contingent liabilities, and may create integration difficulties.

As part of our business strategy, we intend to acquire businesses or assets we believe complement our existing operations. We may not be able to successfully integrate recent or any future acquisitions into our existing operations or achieve the desired profitability from such acquisitions. These acquisitions may require substantial capital expenditures and the incurrence of additional indebtedness. If we make acquisitions, our capitalization and results of operations may change significantly. Further, any acquisition could result in:

- post-closing discovery of material undisclosed liabilities of the acquired business or assets;

- the unexpected loss of key employees or customers from the acquired businesses;
- difficulties resulting from our integration of the operations, systems and management of the acquired business; and
- an unexpected diversion of our management's attention from other operations.

Table of Contents

If recent or any future acquisitions are unsuccessful or result in unanticipated events or if we are unable to successfully integrate acquisitions into our existing operations, such acquisitions could adversely affect our results of operations, cash flow and ability to make distributions to our unitholders.

Adverse weather conditions, including droughts, hurricanes, tropical storms and other severe weather, could reduce our results of operations and ability to make distributions to our unitholders.

Our distribution network and operations are primarily concentrated in the Gulf Coast region and along the Mississippi River inland waterway. Weather in these regions is sometimes severe (including tropical storms and hurricanes) and can be a major factor in our day-to-day operations. Our marine transportation operations can be significantly delayed, impaired or postponed by adverse weather conditions, such as fog in the winter and spring months and certain river conditions. Additionally, our marine transportation operations and our assets in the Gulf of Mexico, including our barges, push boats, tugboats and terminals, can be adversely impacted or damaged by hurricanes, tropical storms, tidal waves or other related events. Demand for our lubricants and the diesel fuel we throughput in our terminalling and storage segment can be affected if offshore drilling operations are disrupted by weather in the Gulf of Mexico.

National weather conditions have a substantial impact on the demand for our products. Unusually warm weather during the winter months can cause a significant decrease in the demand for NGL products, fuel oil and gasoline. Likewise, extreme weather conditions (either wet or dry) can decrease the demand for fertilizer. For example, an unusually wet spring can delay planting of seeds, which can leave insufficient time to apply fertilizer at the planting stage. Conversely, drought conditions can kill or severely stunt the growth of crops, thus eliminating the need to nurture plants with fertilizer. Any of these or similar conditions could result in a decline in our net income and cash flow, which would reduce our ability to make distributions to our unitholders.

If we incur material liabilities that are not fully covered by insurance, such as liabilities resulting from accidents on rivers or at sea, spills, fires or explosions, our results of operations and ability to make distributions to our unitholders could be adversely affected.

Our operations are subject to the operating hazards and risks incidental to terminalling and storage, marine transportation and the distribution of petroleum products and by-products and other industrial products. These hazards and risks, many of which are beyond our control, include:

- accidents on rivers or at sea and other hazards that could result in releases, spills and other environmental damages, personal injuries, loss of life and suspension of operations;
- leakage of NGLs and other petroleum products and by-products;
- fires and explosions;
- damage to transportation, terminalling and storage facilities, and surrounding properties caused by natural disasters; and
- terrorist attacks or sabotage.

Our insurance coverage may not be adequate to protect us from all material expenses related to potential future claims for personal-injury and property damage, including various legal proceedings and litigation resulting from these hazards and risks. If we incur material liabilities that are not covered by insurance, our operating results, cash flow and ability to make distributions to our unitholders could be adversely affected.

Changes in the insurance markets attributable to the September 11, 2001, terrorist attacks and their aftermath may make some types of insurance more difficult or expensive for us to obtain. In addition, changes in the insurance markets attributable to the effects of Hurricanes Katrina, Rita and Ike and their aftermath may make some types of insurance more difficult or expensive for us to obtain. As a result, we may be unable to secure the levels and types of insurance we would otherwise have secured prior to such events. Moreover, the insurance that may be available to us may be significantly more expensive than our existing insurance coverage.

The price volatility of petroleum products and by-products can reduce our liquidity and results of operations and ability to make distributions to our unitholders.

We purchase hydrocarbon products and by-products, such as molten sulfur, sulfur derivatives, fuel oils, LPGs, lubricants, asphalt and other bulk liquids, and sell these products to wholesale and bulk customers and to other end users. We also generate revenues through the terminalling and storage of certain products for third parties. The price and market value of hydrocarbon products and by-products can be, and has recently been, volatile. Our liquidity and revenues have been adversely affected by this volatility during periods of decreasing prices because of the reduction in the value and resale price of our inventory. In addition, our liquidity and costs have been adversely affected during periods of increasing prices because of the increased costs associated with our purchase of hydrocarbon products and by-products. Future price volatility could have an adverse impact on our liquidity and results of operations, cash flow and ability to make distributions to our unitholders.

Table of Contents

Increasing energy prices could adversely affect our results of operations.

Increasing energy prices, such as those experienced in the past couple of years, could adversely affect our results of operations. Diesel fuel, natural gas, chemicals and other supplies are recorded in operating expenses. An increase in price of these products would increase our operating expenses, which could adversely affect our results of operations including net income and cash flows. We cannot assure unitholders that we will be able to pass along increased operating expenses to our customers.

Increased competition from alternative natural gas transportation and storage options and alternative fuel sources could have a significant financial impact on us.

Our ability to renew or replace existing contracts at rates sufficient to maintain current revenues and cash flows could be adversely affected by activities of other interstate and intrastate pipelines and storage facilities that may expand or construct competing transportation and storage systems. In addition, future pipeline transportation and storage capacity could be constructed in excess of actual demand and with lower fuel requirements, operating and maintenance costs than our facilities, which could reduce the demand for and the rates that we receive for our services in particular areas. Further, natural gas also competes with alternative energy sources available to our customers that are used to generate electricity, such as hydroelectric power, solar, wind, nuclear, coal and fuel oil.

Demand for our terminalling and storage services is substantially dependent on the level of offshore oil and gas exploration, development and production activity.

The level of offshore oil and gas exploration, development and production activity historically has been volatile and is likely to continue to be so in the future. The level of activity is subject to large fluctuations in response to relatively minor changes in a variety of factors that are beyond our control, including:

- prevailing oil and natural gas prices and expectations about future prices and price volatility;
- the cost of offshore exploration for, and production and transportation of, oil and natural gas;
- worldwide demand for oil and natural gas;
- consolidation of oil and gas and oil service companies operating offshore;
- availability and rate of discovery of new oil and natural gas reserves in offshore areas;
- local and international political and economic conditions and policies;
- technological advances affecting energy production and consumption;
- weather conditions;
- environmental regulation; and
- the ability of oil and gas companies to generate or otherwise obtain funds for exploration and production.

We expect levels of offshore oil and gas exploration, development and production activity to continue to be volatile and affect demand for our terminalling and storage services.

Our NGL and sulfur-based fertilizer products are subject to seasonal demand and could cause our revenues to vary.

The demand for NGL and natural gas is highest in the winter. Therefore, revenue from our natural gas services business is higher in the winter than in other seasons. Our sulfur-based fertilizer products experience an increase in demand during the spring, which increases the revenue generated by this business line in this period compared to other periods. The seasonality of the revenue from these products may cause our results of operations to vary on a quarter-to-quarter basis and thus could cause our cash available for quarterly distributions to fluctuate from period to period.

The highly competitive nature of our industry could adversely affect our results of operations and ability to make distributions to our unitholders.

We operate in a highly competitive marketplace in each of our primary business segments. Most of our competitors in each segment are larger companies with greater financial and other resources than we possess. We may lose customers and future business opportunities to our competitors and any such losses could adversely affect our results of operations and ability to make distributions to our unitholders.

Our business is subject to compliance with environmental laws and regulations that may expose us to significant costs and liabilities and adversely affect our results of operations and ability to make distributions to our unitholders.

Our business is subject to federal, state and local environmental laws and regulations governing the discharge of materials into the environment or otherwise relating to protection of human health, natural resources and the environment. These laws and regulations may impose numerous obligations that are applicable to our operations, such as requiring the acquisition of permits to conduct regulated activities; restricting the manner in which we can release materials into the environment; requiring remedial activities or capital expenditures to mitigate pollution from former or current operations and imposing substantial liabilities on us for pollution resulting from our operations. Numerous governmental authorities, such as the U.S. Environmental Protection Agency and analogous state agencies, have the power to enforce compliance with these laws and regulations and the permits issued under them, oftentimes requiring difficult and costly actions. Many environmental laws and regulations can impose joint and several strict liability, and any failure to comply with environmental laws, regulations and permits may result in the assessment of administrative, civil and criminal penalties, the imposition of investigatory and remedial obligations and, in some circumstances, the issuance of injunctions that can limit or prohibit our operations. The clear trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment, and, thus, any changes in environmental laws and regulations that result in more stringent and costly waste handling, storage, transport, disposal or remediation requirements could have a material adverse effect on our operations and financial position.

The loss or insufficient attention of key personnel could negatively impact our results of operations and ability to make distributions to our unitholders.

Our success is largely dependent upon the continued services of members of the senior management team of Martin Resource Management. Those senior executive officers have significant experience in our businesses and have developed strong relationships with a broad range of industry participants. The loss of any of these executives could have a material adverse effect on our relationships with these industry participants, our results of operations and our ability to make distributions to our unitholders.

We do not have employees. We rely solely on officers and employees of Martin Resource Management to operate and manage our business. Martin Resource Management operates businesses and conducts activities of its own in which we have no economic interest. There could be competition for the time and effort of the officers and employees who provide services to our general partner. If these officers and employees do not or cannot devote sufficient attention to the management and operation of our business, our results of operation and ability to make distributions to our unitholders may be reduced.

Our loss of significant commercial relationships with Martin Resource Management could adversely impact our results of operations and ability to make distributions to our unitholders.

Martin Resource Management provides us with various services and products pursuant to various commercial contracts. The loss of any of these services and products provided by Martin Resource Management could have a material adverse impact on our results of operations, cash flow and ability to make distributions to our unitholders. Additionally, we provide terminalling and storage, processing and marine transportation services to Martin Resource Management to support its businesses under various commercial contracts. The loss of Martin Resource Management as a customer could have a material adverse impact on our results of operations, cash flow and ability to make distributions to our unitholders.

Our business would be adversely affected if operations at our transportation, terminalling and storage and distribution facilities experienced significant interruptions. Our business would also be adversely affected if the operations of our customers and suppliers experienced significant interruptions.

Our operations are dependent upon our terminalling and storage facilities and various means of transportation. We are also dependent upon the uninterrupted operations of certain facilities owned or operated by our suppliers and customers. Any significant interruption at these facilities or inability to transport products to or from these facilities or to or from our customers for any reason would adversely affect our results of operations, cash flow and ability to make distributions to our unitholders. Operations at our facilities and at the facilities owned or operated by our suppliers and customers could be partially or completely shut down, temporarily or permanently, as the result of any number of circumstances that are not within our control, such as:

- catastrophic events, including hurricanes;
- environmental remediation;
- labor difficulties; and
- disruptions in the supply of our products to our facilities or means of transportation.

Additionally, terrorist attacks and acts of sabotage could target oil and gas production facilities, refineries, processing plants, terminals and other infrastructure facilities. Any significant interruptions at our facilities, facilities owned or operated by our suppliers or customers, or in the oil and gas industry as a whole caused by such attacks or acts could have a material adverse affect on our results of operations, cash flow and ability to make distributions to our unitholders.

Political, regulatory and economic factors may significantly affect our operations, the manner in which we conduct our business and slow our rate of growth.

Due to changes in the political climate as a result of the outcome of recent state elections and the Congressional election in the United States, we cannot predict with any certainty the nature and extent of the changes in federal, state and local laws, regulations and policy we will face, or the effect of such elections on any pending legislation. Any increased regulation, new policy initiatives, increased taxes or any other changes in federal law may have an adverse effect on our business, financial condition and results of operations.

Our marine transportation business would be adversely affected if we do not satisfy the requirements of the Jones Act or if the Jones Act were modified or eliminated.

The Jones Act is a federal law that restricts domestic marine transportation in the United States to vessels built and registered in the United States. Furthermore, the Jones Act requires that the vessels be manned and owned by United States citizens. If we fail to comply with these requirements, our vessels lose their eligibility to engage in coastwise trade within United States domestic waters.

The requirements that our vessels be United States built and manned by United States citizens, the crewing requirements and material requirements of the Coast Guard and the application of United States labor and tax laws significantly increase the costs of United States flagged vessels when compared with foreign-flagged vessels. During the past several years, certain interest groups have lobbied Congress to repeal the Jones Act to facilitate foreign flag competition for trades and cargoes reserved for United States flagged vessels under the Jones Act and cargo preference laws. If the Jones Act were to be modified to permit foreign competition that would not be subject to the same United States government imposed costs, we may need to lower the prices we charge for our services in order to compete with foreign competitors, which would adversely affect our cash flow and ability to make distributions to our unitholders. Following Hurricane Katrina and again after Hurricane Rita, emergency suspensions of the Jones Act were effectuated by the United States government. The last suspension ended on October 24, 2005. Future suspensions of the Jones Act or other similar actions could result in similar consequences.

Our marine transportation business would be adversely affected if the United States Government purchases or requisitions any of our vessels under the Merchant Marine Act.

We are subject to the Merchant Marine Act of 1936, which provides that, upon proclamation by the President of the United States of a national emergency or a threat to the national security, the United States Secretary of Transportation may requisition or purchase any vessel or other watercraft owned by United States citizens (including us, provided that we are considered a United States citizen for this purpose). If one of our push boats, tugboats or tank barges were purchased or requisitioned by the United States government under this law, we would be entitled to be paid the fair market value of the vessel in the case of a purchase or, in the case of a requisition, the fair market value of charter hire. However, if one of our push boats or tugboats is requisitioned or purchased and its associated tank barge is left idle, we would not be entitled to receive any compensation for the lost revenues resulting from the idled barge. We also would not be entitled to be compensated for any consequential damages we suffer as a result of the requisition or purchase of any of our push boats, tugboats or tank barges. If any of our vessels are purchased or requisitioned for an extended period of time by the United States government, such transactions could have a material adverse affect on our results of operations, cash flow and ability to make distributions to our unitholders.

Table of Contents

Regulations affecting the domestic tank vessel industry may limit our ability to do business, increase our costs and adversely impact our results of operations and ability to make distributions to our unitholders.

The OPA 90 provides for the phase out of single-hull vessels and the phase-in of the exclusive operation of double-hull tank vessels in U.S. waters for barges that carry petroleum products that are regulated under OPA. Under OPA, substantially all tank vessels that do not have double hulls will be phased out by 2015 and will not be permitted to enter U.S. ports or trade in U.S. waters. The phase-out dates vary based on the age of the vessel and other factors. All but one of our offshore tank barges are double-hull vessels that have no phase out date. We have five single-hull barges that will be phased out of the petroleum product trade by the year 2015. The phase out of these single-hull vessels in accordance with OPA may require us to make substantial capital expenditures, which could adversely affect our operations and market position and reduce our cash available for distribution.

Our profitability is dependent upon prices and market demand for natural gas and NGLs, which are beyond our control and have been volatile.

We are subject to significant risks due to fluctuations in commodity prices. These risks relate primarily to: (1) the purchase of certain volumes of natural gas at a price that is a percentage of a relevant index and (2) certain processing contracts for Prism Gas whereby we are exposed to natural gas and NGL commodity price risks.

The margins we realize from purchasing and selling a portion of the natural gas that we transport through our pipeline systems decrease in periods of low natural gas prices because our gross margins are based on a percentage of the index price. For the years ended December 31, 2010, and 2009, Prism Gas purchased approximately 18% and 19%, respectively, of our gas at a percentage of relevant index. Accordingly, a decline in the price of natural gas could have an adverse impact on our results of operations.

In the past, the prices of natural gas and NGLs have been extremely volatile and we expect this volatility to continue. For example, in 2009, the spot price of Henry Hub natural gas ranged from a high of $6.10 per MMBtu to a low of $1.84 per MMBtu. In 2010, the same price ranged from $7.51 per MMBtu to $3.18 per MMBtu. On December 31, 2010, the spot price was $4.22 per MMBtu.

We may not be successful in balancing our purchases and sales. In addition, a producer could fail to deliver contracted volumes or deliver in excess of contracted volumes, or a consumer could purchase less than contracted volumes. Any of these actions could cause our purchases and sales not to be balanced. If our purchases and sales are not balanced, we will face increased exposure to commodity price risks and could have increased volatility in our operating income.

The markets and prices for residue gas and NGLs depend upon factors beyond our control. These factors include demand for oil, natural gas and NGLs, which fluctuate with changes in market and economic conditions and other factors, including:

- the impact of weather on the demand for oil and natural gas;
- the level of domestic oil and natural gas production;
- the level of domestic industrial and manufacturing activity;
- the availability of imported oil and natural gas;
- actions taken by foreign oil and gas producing nations;

- the availability of local, intrastate and interstate transportation systems;
- the availability and marketing of competitive fuels;

- the impact of energy conservation efforts; and
- the extent of governmental regulation and taxation.

Our commodity hedging activities may have a material adverse effect on our earnings, profitability, liquidity, cash flows and financial condition.

As of December 31, 2010, Prism Gas has hedged approximately 37% and 10% of its commodity risk by volume for 2011 and 2012, respectively. As of March 2, 2011, Prism Gas has hedged approximately 45% and 14% of its commodity risk by volume for 2011 and 2012, respectively.

These hedging arrangements are in the form of swaps for crude oil, natural gas and natural gasoline. We anticipate entering into additional hedges in 2011 and beyond to further reduce our exposure to commodity price movements. The intent of these arrangements is to reduce the volatility in our cash flows resulting from fluctuations in commodity prices.

We entered into these derivative transactions with investment grade banks. While we anticipate that future derivative transactions will be entered into with investment grade counterparties, and that we will actively monitor the credit rating of such counterparties, it is nevertheless possible that losses will result from counterparty credit risk in the future.

Management will continue to evaluate whether to enter into any new hedging arrangements, but there can be no assurance that we will enter into any new hedging arrangements or that our future hedging arrangements will be on terms similar to our existing hedging arrangements. Also, we may seek in the future to further limit our exposure to changes in natural gas, NGL and condensate commodity prices, and we may seek to limit our exposure to changes in interest rates by using financial derivative instruments and other hedging mechanisms from time to time. To the extent we hedge our commodity price and interest rate risk we may forego the benefits we would otherwise experience if commodity prices or interest rates were to change in our favor.

Despite our hedging program, we remain exposed to risks associated with fluctuations in commodity prices. The extent of our commodity price risk is related largely to the effectiveness and scope of our hedging activities. For example, the derivative instruments we utilize are based on posted market prices, which may differ significantly from the actual natural gas, NGL and condensate prices that we realize in our operations. Furthermore, we have entered into derivative transactions related to only a portion of the volume of our expected natural gas supply and production of NGLs and condensate from our processing plants; as a result, we will continue to have direct commodity price risk to the unhedged portion. Our actual future production may be significantly higher or lower than we estimated at the time we entered into the derivative transactions for that period. If the actual amount is higher than we estimated, we will have greater commodity price risk than we intended. If the actual amount is lower than the amount that is subject to our derivative financial instruments, we might be forced to satisfy all or a portion of our derivative transactions without the benefit of the cash flow from our sale of the underlying physical commodity, resulting in a reduction of our liquidity.

As a result of these factors, our hedging activities may not be as effective as we intend in reducing the volatility of our cash flows, and in certain circumstances may actually increase the volatility of our cash flows. In addition, even though our management monitors our hedging activities, these activities can result in substantial losses. Such losses could occur under various circumstances, including if a counterparty does not perform its obligations under the applicable hedging arrangement, the hedging arrangement is imperfect or ineffective, or our hedging policies and procedures are not properly followed or do not perform as planned. We cannot assure our unitholders that the steps we take to monitor our hedging activities will detect and prevent violations of our risk management policies and procedures, particularly if deception or other intentional misconduct is involved. For additional information regarding our hedging activities, please see "Item 7A. Quantitative and Qualitative Disclosures about Market Risk — Commodity Price Risk."

Our interest rate swap activities may have a material adverse effect on our earnings, profitability, liquidity, cash flows and financial condition.

We are subject to interest rate risks associated with interest rate swap agreements related to our Senior Notes. Pursuant to the terms of these interest rate swap agreements, we pay a variable rate interest payment based on the three-month LIBOR and receive a fixed rate. The risk associated with these interest rate swaps exposes us to an increase in interest rates which would result in an increase in interest expense and a corresponding decrease in net income. For additional information regarding our interest rate swap activities, please see "Item 7A. Quantitative and Qualitative Disclosures about Market Risk — Interest Rate Risk."

Table of Contents

The industry in which we operate is highly competitive, and increased competitive pressure could adversely affect our business and operating results.

We compete with similar enterprises in our respective areas of operation. Some of our competitors are large oil, natural gas and petrochemical companies that have greater financial resources and access to supplies of natural gas and NGLs than we do. Some of these competitors may expand or construct gathering, processing and transportation systems that would create additional competition for the services we provide to our customers. In addition, our customers who are significant producers of natural gas may develop their own gathering, processing and transportation systems in lieu of using ours. Likewise, our customers who produce NGLs may develop their own systems to transport NGLs in lieu of using ours. Our ability to renew or replace existing contracts with our customers at rates sufficient to maintain current revenues and cash flows could be adversely affected by the activities of our competitors and our customers. All of these competitive pressures could have a material adverse effect on our business, results of operations, financial condition and ability to make cash distributions to our unitholders.

A change in the jurisdictional characterization of some of our assets by federal, state or local regulatory agencies or a change in policy by those agencies may result in increased regulation of our assets, which may cause our revenues to decline and operating expenses to increase.

We believe that our natural gas gathering operations meet the tests the FERC uses to establish a pipeline’s status as a gatherer exempt from FERC regulation under the NGA, but FERC regulation still affects these businesses and the markets for products derived from these businesses. FERC’s policies and practices across the range of its oil and natural gas regulatory activities, including, for example, its policies on open access transportation, ratemaking, capacity release and market center promotion, indirectly affect intrastate markets. In recent years, FERC has pursued pro-competitive policies in its regulation of interstate oil and natural gas pipelines. However, we cannot assure our unitholders that FERC will continue this approach as it considers matters such as pipeline rates and rules and policies that may affect rights of access to oil and natural gas transportation capacity. In addition, the distinction between FERC-regulated transmission services and federally unregulated gathering services has been the subject of regular litigation, so, in such a circumstance, the classification and regulation of some of our gathering facilities and intrastate transportation pipelines may be subject to change based on future determinations by FERC and the courts.

Other state and local regulations also affect our business. Our gathering lines are subject to ratable-take and common-purchaser statutes in Louisiana and Texas. Ratable-take statutes generally require gatherers to take, without undue discrimination, oil or natural gas production that may be tendered to the gatherer for handling. Similarly, common purchaser statutes generally require gatherers to purchase without undue discrimination as to source of supply or producer. These statutes restrict our right as an owner of gathering facilities to decide with whom we contract to purchase or transport oil or natural gas. Federal law leaves any economic regulation of natural gas gathering to the states. The states in which we operate have adopted complaint-based regulation of oil and natural gas gathering activities, which allows oil and natural gas producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to oil and natural gas gathering access and rate discrimination. Other state regulations may not directly regulate our business, but may nonetheless affect the availability of natural gas for purchase, processing and sale, including state regulation of production rates and maximum daily production allowable from gas wells. While our gathering lines currently are subject to limited state regulation, there is a risk that state laws will be changed, which may give producers a stronger basis to challenge the rates, terms and conditions of a gathering line providing transportation service.

Panther Interstate Pipeline Energy, LLC is also subject to regulation by FERC with respect to issues other than ratemaking.

Under the NGA, FERC has the authority to regulate natural gas companies, such as Panther Interstate Pipeline Energy, LLC with respect to: rates, terms and conditions of service; the types of services Panther Interstate Pipeline Energy, LLC may provide to its customers; the construction of new facilities; the acquisition, extension, expansion or abandonment of services or facilities; the maintenance and retention of accounts and records; and relationships of affiliated companies involved in all aspects of the natural gas and energy business. FERC's actions in any of these areas or modifications to its current regulations could impair Panther Interstate Pipeline Energy, LLC's ability to compete for business, the costs it incurs to operate, or the acquisition or construction of new facilities.

Table of Contents

We may incur significant costs and liabilities resulting from pipeline integrity programs and related repairs.

Pursuant to the Pipeline Safety Improvement Act of 2002, the DOT has adopted regulations requiring pipeline operators to develop integrity management programs for transportation pipelines located where a leak or rupture could do the most harm in "high consequence areas." The regulations require operators to:

- perform ongoing assessments of pipeline integrity;
- identify and characterize applicable threats to pipeline segments that could impact a high consequence area;
- improve data collection, integration and analysis;
- repair and remediate the pipeline as necessary; and
- implement preventive and mitigating actions.

We currently estimate that we will incur costs of less than $0.5 million between 2010 and 2012 to implement pipeline integrity management program testing along certain segments of our natural gas and NGL pipelines. This does not include the costs, if any, of any repair, remediation, preventative or mitigating actions that may be determined to be necessary as a result of the testing program, which costs could be substantial.

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

We do not own all of the land on which our pipelines and facilities have been constructed, and we are therefore subject to the possibility of more onerous terms and/or increased costs to retain necessary land use if we do not have valid rights of way or if such rights of way lapse or terminate. We obtain the rights to construct and operate our pipelines on land owned by third parties and governmental agencies for a specific period of time. Our loss of these rights, through our inability to renew right-of-way contracts or otherwise, could have a material adverse effect on our business, results of operations and financial condition and our ability to make cash distributions to our unitholders.

Risks Relating to an Investment in the Common Units

Units available for future sales by us or our affiliates could have an adverse impact on the price of our common units or on any trading market that may develop.

Martin Resource Management through its subsidiaries currently holds 889,444 subordinated units and 5,703,823 common units. The subordinated units will have no distribution rights until February 2012. At the end of such second anniversary, the subordinated units will automatically convert to common units, having the same distribution rights as existing common units.

Common units will generally be freely transferable without restriction or further registration under the Securities Act, except that any common units held by an "affiliate" of ours may not be resold publicly except in compliance with the registration requirements of the Securities Act or under an exemption under Rule 144 or otherwise.

Our partnership agreement provides that we may issue an unlimited number of limited partner interests of any type without a vote of the unitholders. Our general partner may also cause us to issue an unlimited number of additional common units or other equity securities of equal rank with the common units, without unitholder approval, in a number of circumstances such as:

- the issuance of common units in additional public offerings or in connection with acquisitions that increase cash flow from operations on a pro forma, per unit basis;
- the conversion of subordinated units into common units;
- the conversion of units of equal rank with the common units into common units under some circumstances; or
- the conversion of our general partner’s general partner interest in us and its incentive distribution rights into common units as a result of the withdrawal of our general partner.

Our partnership agreement does not restrict our ability to issue equity securities ranking junior to the common units at any time. Any issuance of additional common units or other equity securities would result in a corresponding decrease in the proportionate ownership interest in us represented by, and could adversely affect the cash distributions to and market price of, common units then outstanding.

Table of Contents

Under our partnership agreement, our general partner and its affiliates have the right to cause us to register under the Securities Act and applicable state securities laws the offer and sale of any units that they hold. Subject to the terms and conditions of our partnership agreement, these registration rights allow the general partner and its affiliates or their assignees holding any units to require registration of any of these units and to include any of these units in a registration by us of other units, including units offered by us or by any unitholder. Our general partner will continue to have these registration rights for two years following its withdrawal or removal as a general partner. In connection with any registration of this kind, we will indemnify each unitholder participating in the registration and its officers, directors, and controlling persons from and against any liabilities under the Securities Act or any applicable state securities laws arising from the registration statement or prospectus. Except as described below, the general partner and its affiliates may sell their units in private transactions at any time, subject to compliance with applicable laws. Our general partner and its affiliates, with our concurrence, have granted comparable registration rights to their bank group to which their partnership units have been pledged.

The sale of any common or subordinated units could have an adverse impact on the price of the common units or on any trading market that may develop.

Unitholders have less power to elect or remove management of our general partner than holders of common stock in a corporation. It is unlikely that our common unitholders will have sufficient voting power to elect or remove our general partner without the consent of Martin Resource Management and its affiliates.

Unlike the holders of common stock in a corporation, unitholders have only limited voting rights on matters affecting our business and therefore limited ability to influence management's decisions regarding our business. Unitholders did not elect our general partner or its directors and will have no right to elect our general partner or its directors on an annual or other continuing basis. Martin Resource Management elects the directors of our general partner. Although our general partner has a fiduciary duty to manage our partnership in a manner beneficial to us and our unitholders, the directors of our general partner also have a fiduciary duty to manage our general partner in a manner beneficial to Martin Resource Management and its shareholders.

If unitholders are dissatisfied with the performance of our general partner, they will have a limited ability to remove our general partner. Our general partner generally may not be removed except upon the vote of the holders of at least 66 2/3% of the outstanding units voting together as a single class. Martin Resource Management owns an approximate 31.6% limited partnership interest in us. Therefore, it is unlikely that our general partner would be removed involuntarily without the consent of one or more affiliates of our general partner.

Unitholders' voting rights are further restricted by our partnership agreement provision prohibiting any units held by a person owning 20% or more of any class of units then outstanding, other than our general partner, its affiliates, their transferees and persons who acquired such units with the prior approval of our general partner's directors, from voting on any matter. In addition, our partnership agreement contains provisions limiting the ability of unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting the unitholders' ability to influence the manner or direction of management.

As a result of these provisions, it will be more difficult for a third party to acquire our partnership without first negotiating the acquisition with our general partner. Consequently, it is unlikely the trading price of our common units will ever reflect a takeover premium.

Our general partner's discretion in determining the level of our cash reserves may adversely affect our ability to make cash distributions to our unitholders.

Our partnership agreement requires our general partner to deduct from operating surplus cash reserves it determines in its reasonable discretion to be necessary to fund our future operating expenditures. In addition, our partnership agreement permits our general partner to reduce available cash by establishing cash reserves for the proper conduct of our business, to comply with applicable law or agreements to which we are a party or to provide funds for future distributions to partners. These cash reserves will affect the amount of cash available for distribution to our unitholders.

Unitholders may not have limited liability if a court finds that we have not complied with applicable statutes or that unitholder action constitutes control of our business.

The limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established in some states. The holder of one of our common units could be held liable in some circumstances for our obligations to the same extent as a general partner if a court were to determine that:

- we had been conducting business in any state without compliance with the applicable limited partnership statute or

- the right or the exercise of the right by our unitholders as a group to remove or replace our general partner, to approve some amendments to our partnership agreement, or to take other action under our partnership agreement constituted participation in the "control" of our business.

Our general partner generally has unlimited liability for our obligations, such as our debts and environmental liabilities, except for our contractual obligations that are expressly made without recourse to our general partner. In addition, under some circumstances, a unitholder may be liable to us for the amount of a distribution for a period of nine years from the date of the distribution.

Our partnership agreement contains provisions that reduce the remedies available to unitholders for actions that might otherwise constitute a breach of fiduciary duty by our general partner.

Our partnership agreement limits the liability and reduces the fiduciary duties of our general partner to the unitholders. Our partnership agreement also restricts the remedies available to unitholders for actions that would otherwise constitute breaches of our general partner's fiduciary duties. For example, our partnership agreement:

- permits our general partner to make a number of decisions in its "sole discretion." This entitles our general partner to consider only the interests and factors that it desires, and it has no duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or any limited partner;

- provides that our general partner is entitled to make other decisions in its "reasonable discretion," which may reduce the obligations to which our general partner would otherwise be held;

- generally provides that affiliated transactions and resolutions of conflicts of interest not involving a required vote of unitholders must be "fair and reasonable" to us and that, in determining whether a transaction or resolution is "fair and reasonable," our general partner may consider the interests of all parties involved, including its own; and

- provides that our general partner and its officers and directors will not be liable for monetary damages to us, our limited partners or assignees for errors of judgment or for any acts or omissions if our general partner and those other persons acted in good faith.

Unitholders are treated as having consented to the various actions contemplated in our partnership agreement and conflicts of interest that might otherwise be considered a breach of fiduciary duties under applicable state law.

We may issue additional common units without unitholder approval, which would dilute unitholder ownership interests.

Our general partner may also cause us to issue an unlimited number of additional common units or other equity securities of equal rank with the common units, without unitholder approval, in a number of circumstances such as:

- the issuance of common units in additional public offerings or in connection with acquisitions that increase cash flow from operations on a pro forma, per unit basis;
- the conversion of subordinated units into common units;
- the conversion of units of equal rank with the common units into common units under some circumstances; or
- the conversion of our general partner's general partner interest in us and its incentive distribution rights into common units as a result of the withdrawal of our general partner.

We may issue an unlimited number of limited partner interests of any type without the approval of our unitholders. Our partnership agreement does not give our unitholders the right to approve our issuance of equity securities ranking junior to the common units at any time.

Table of Contents

The issuance of additional common units or other equity securities of equal or senior rank will have the following effects:

- our unitholders' proportionate ownership interest in us will decrease;
- the amount of cash available for distribution on a per unit basis may decrease;
- because a lower percentage of total outstanding units will be subordinated units, the risk that a shortfall in the payment of the minimum quarterly distribution will be borne by our common unitholders will increase;
- the relative voting strength of each previously outstanding unit will diminish;
- the market price of the common units may decline; and
- the ratio of taxable income to distributions may increase.

The control of our general partner may be transferred to a third party, and that party could replace our current management team, without unitholder consent. Additionally, if Martin Resource Management no longer controls our general partner, amounts we owe under our credit facility may become immediately due and payable.

Our general partner may transfer its general partner interest to a third party in a merger or in a sale of all or substantially all of its assets without the consent of the unitholders. Furthermore, there is no restriction in our partnership agreement on the ability of the owner of our general partner to transfer its ownership interest in our general partner to a third party. A new owner of our general partner could replace the directors and officers of our general partner with its own designees and control the decisions taken by our general partner. Martin Resource Management and its affiliates have pledged their interests in our general partner and us to their bank group. If, at any time, Martin Resource Management no longer controls our general partner, the lenders under our credit facility may declare all amounts outstanding thereunder immediately due and payable. If such event occurs, we may be required to refinance our debt on unfavorable terms, which could negatively impact our results of operations and our ability to make distribution to our unitholders.

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

If at any time our general partner and its affiliates own more than 80% of the common units, our general partner will have the right, but not the obligation, which it may assign to any of its affiliates or to us, to acquire all, but not less than all, of the remaining common units held by unaffiliated persons at a price not less than the then-current market price. As a result, unitholders may be required to sell their common units at an undesirable time or price and may not receive any return on their investment. Unitholders may also incur a tax liability upon a sale of their units. No provision in our partnership agreement, or in any other agreement we have with our general partner or Martin Resource Management, prohibits our general partner or its affiliates from acquiring more than 80% of our common units. For additional information about this call right and unitholders' potential tax liability, please see "Risk Factors — Tax Risks — Tax gain or loss on the disposition of our common units could be different than expected."

Our common units have a limited trading volume compared to other publicly traded securities.

Our common units are quoted on the Nasdaq Global Select Market ("NASDAQ") under the symbol "MMLP." However, daily trading volumes for our common units are, and may continue to be, relatively small compared to many other securities quoted on the NASDAQ. The price of our common units may, therefore, be volatile.

Failure to achieve and maintain effective internal controls in accordance with Section 404 of the Sarbanes–Oxley Act could have a material adverse effect on our unit price.

In order to comply with Section 404 of the Sarbanes–Oxley Act, we periodically document and test our internal control procedures. Section 404 of the Sarbanes–Oxley Act requires annual management assessments of the effectiveness of our internal controls over financial reporting addressing these assessments. During the course of our testing we may identify deficiencies, which we may not be able to address in time to meet the deadline imposed by the Sarbanes–Oxley Act for compliance with the requirements of Section 404. In addition, if we fail to maintain the adequacy of our internal controls, as such standards are modified, supplemented or amended from time to time, we may not be able to ensure that we can conclude on an ongoing basis that we have effective internal controls over financial reporting in accordance with Section 404 of the Sarbanes–Oxley Act. Failure to achieve and maintain an effective internal control environment could have a material adverse effect on the price of our common units.

Risks Relating to Our Relationship with Martin Resource Management

Existing litigation between Ruben Martin and Scott Martin and related parties concerning the ownership, management and operation of Martin Resource Management, the owner of our General Partner, could adversely affect us.

There are several pending lawsuits between Ruben Martin, the President, Chief Executive Officer and member of the board of directors of our General Partner, and Scott Martin, who is Ruben Martin's brother, and related parties concerning the ownership, management and operation of Martin Resource Management, the owner of our General Partner. We are not a party to any of those lawsuits and they do not assert any claims (i) against us, (ii) concerning our governance or operations or (iii) against our directors, officers or employees with respect to their service to us. The existence of those lawsuits, however, including any ultimate outcomes that might be deemed negative to us or our existing management team could adversely affect our ability to access capital markets or obtain additional credit or negatively impact our business, results of operations and/or ability to make distributions to our unitholders. Any similar effects from such litigation on Martin Resource Management or its existing management team could also adversely affect us.

In addition, such litigation, depending on its ultimate outcome, could also result in changes in the existing boards of directors and management teams of Martin Resource Management and us. To the extent that any such adverse circumstances occur, they could be deemed by our lenders to have a "material adverse effect" on us, thereby providing such lenders with an opportunity to prohibit further borrowings by us under our credit facility and, depending on the circumstances, assert that an event of default exists thereunder. If any such event of default exists and is continuing, then, upon the election of our lenders, all outstanding amounts due under our credit facility could be accelerated and could become immediately due and payable. Similarly, a negative outcome in such litigation could result in a similar result under the credit facility maintained by Martin Resource Management. While any such litigation remains pending, there can be no assurance that the litigation parties adverse to our existing management team or the existing management team of Martin Resource Management will not seek to disrupt, delay or postpone any future attempts by us to access the capital markets.

For a more detailed discussion of these pending litigation matters, please see "Item 9B. Other Information —Existing Litigation at Martin Resource Management."

Cash reimbursements due to Martin Resource Management may be substantial and will reduce our cash available for distribution to our unitholders.

Under our omnibus agreement with Martin Resource Management, Martin Resource Management provides us with corporate staff and support services on behalf of our general partner that are substantially identical in nature and quality to the services it conducted for our business prior to our formation. The omnibus agreement requires us to reimburse Martin Resource Management for the costs and expenses it incurs in rendering these services, including an overhead allocation to us of Martin Resource Management's indirect general and administrative expenses from its corporate allocation pool. These payments may be substantial. Payments to Martin Resource Management will reduce the amount of available cash for distribution to our unitholders.

Martin Resource Management has conflicts of interest and limited fiduciary responsibilities, which may permit it to favor its own interests to the detriment of our unitholders.

As of March 2, 2011, Martin Resource Management owns an approximate 31.6% limited partnership interest in us. Furthermore, it owns and controls our general partner, which owns a 2.0% general partner interest and incentive distribution rights in us. Conflicts of interest may arise between Martin Resource Management and our general partner, on the one hand, and our unitholders, on the other hand. As a result of these conflicts, our general partner may favor its own interests and the interests of Martin Resource Management over the interests of our unitholders. Potential conflicts of interest between us, Martin Resource Management and our general partner could occur in many of our day-to-day operations including, among others, the following situations:

- Officers of Martin Resource Management who provide services to us also devote significant time to the businesses of Martin Resource Management and are compensated by Martin Resource Management for that time.

- Neither our partnership agreement nor any other agreement requires Martin Resource Management to pursue a business strategy that favors us or utilizes our assets or services. Martin Resource Management's directors and officers have a fiduciary duty to make these decisions in the best interests of the shareholders of Martin Resource Management without regard to the best interests of the unitholders.

- Martin Resource Management may engage in limited competition with us.

Table of Contents

- Our general partner is allowed to take into account the interests of parties other than us, such as Martin Resource Management, in resolving conflicts of interest, which has the effect of reducing its fiduciary duty to our unitholders.

- Under our partnership agreement, our general partner may limit its liability and reduce its fiduciary duties, while also restricting the remedies available to our unitholders for actions that, without the limitations and reductions, might constitute breaches of fiduciary duty. As a result of purchasing units, our unitholders will be treated as having consented to some actions and conflicts of interest that, without such consent, might otherwise constitute a breach of fiduciary or other duties under applicable state law.

- Our general partner determines which costs incurred by Martin Resource Management are reimbursable by us.

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

- Our general partner controls the enforcement of obligations owed to us by Martin Resource Management.

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

- The audit committee of our general partner retains our independent auditors.

- In some instances, our general partner may cause us to borrow funds to permit us to pay cash distributions, even if the purpose or effect of the borrowing is to make incentive distributions.

- Our general partner has broad discretion to establish financial reserves for the proper conduct of our business. These reserves also will affect the amount of cash available for distribution.

Martin Resource Management and its affiliates may engage in limited competition with us.

Martin Resource Management and its affiliates may engage in limited competition with us. For a discussion of the non-competition provisions of the omnibus agreement, please see "Item 13. Certain Relationships and Related Transactions, and Director Independence." If Martin Resource Management does engage in competition with us, we may lose customers or business opportunities, which could have an adverse impact on our results of operations, cash flow and ability to make distributions to our unitholders.

If Martin Resource Management were ever to file for bankruptcy or otherwise default on its obligations under its credit facility, amounts we owe under our credit facility may become immediately due and payable and our results of operations could be adversely affected.

If Martin Resource Management were ever to commence or consent to the commencement of a bankruptcy proceeding or otherwise defaults on its obligations under its credit facility, its lenders could foreclose on its pledge of the interests in our general partner and take control of our general partner. If Martin Resources Management no longer controls our general partner, the lenders under our credit facility may declare all amounts outstanding thereunder immediately due and payable. In addition, either a judgment against Martin Resource Management or a bankruptcy filing by or against Martin Resource Management could independently result in an event of default under our credit facility if it could reasonably be expected to have a material adverse effect on us. If our lenders do declare us in default and accelerate repayment, we may be required to refinance our debt on unfavorable terms, which could negatively impact our results of operations and our ability to make distributions to our unitholders. A bankruptcy filing by or against Martin Resource Management could also result in the termination or material breach of some or all of the various commercial contracts between us and Martin Resource Management, which could have a material adverse impact on our results of operations, cash flow and ability to make distributions to our unitholders.

Table of Contents

Tax Risks

The IRS could treat us as a corporation for tax purposes, which would substantially reduce the cash available for distribution to unitholders.

The anticipated after-tax economic benefit of an investment in us depends largely on our classification as a partnership for federal income tax purposes. Despite the fact that we are organized as a limited partnership under Delaware law, it is possible in certain circumstances for a partnership such as ours to be treated as a corporation for federal income tax purposes. In order for us to be classified as a partnership for U.S. federal income tax purposes, more than 90% of our gross income each year must be “qualifying income” under Section 7704 of the U.S. Internal Revenue Code of 1986, as amended (the “Internal Revenue Code”). “Qualifying income” includes income and gains derived from the transportation, storage, processing and marketing of crude oil, natural gas and products thereof. Other types of qualifying income include interest (other than from a financial business), dividends, gains from the sale of real property and gains from the sale or other disposition of capital assets held for the production of income that otherwise constitutes qualifying income. Thus, “qualifying income” includes income from providing marine transportation services to customers with respect to crude oil, natural gas and certain products thereof but does not include rental income from leasing vessels to customers. The recent decision of the United States Court of Appeals for the Fifth Circuit in Tidewater Inc. v. United States, 565 F.3d 299 (5th Cir. April 13, 2009) held that marine time charter agreements are “leases” that generate rental income for purposes of a foreign sales corporation provision of the Code.

After the Tidewater decision, there was some uncertainty regarding the status of a significant portion of our income as “qualifying income” and, thus, whether we were classified as a partnership for federal income tax purposes. As a result of the Tidewater decision, we requested and obtained a favorable private letter ruling from the U.S. Internal Revenue Service (“IRS”) to confirm that gross income from our marine time charter agreements constitutes “qualifying income” under Section 7704 of the Internal Revenue Code. Additionally, after receiving such private letter ruling from the IRS, the IRS issued Action on Decision 2010-01 I.R.B. 2010-22 on May 17, 2010, stating that the IRS disagreed and did not acquiesce with the Fifth Circuit’s analysis and application of specific factors in the Tidewater case and took the position that time charters should be treated as service contracts and not leases.

Moreover, current law may change so as to cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to entity-level taxation. At the federal level, members of Congress have considered substantive changes to the existing U.S. tax laws that would have affected certain publicly traded partnerships. Although the legislation considered would not have appeared to affect our tax treatment, we are unable to predict whether any such change or other proposals will ultimately be enacted. Moreover, any modification to the federal income tax laws and interpretations thereof may or may not be applied retroactively. Any such changes could negatively impact the value of an investment in our common units. At the state level, because of widespread state budget deficits and other reasons, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. For example, we are required to pay Texas franchise tax at a maximum effective rate of 0.7% of our gross income apportioned to Texas in the prior year. Imposition of any such tax on us by any other state will reduce the cash available for distribution to you.

If we were treated as a corporation for federal income tax purposes, we would owe federal income tax on our income at the corporate tax rate, which is currently a maximum of 35%, and would likely owe state income tax at varying rates. Distributions would generally be taxed again to unitholders as corporate distributions and no income, gains, losses, or deductions would flow through to unitholders. Because a tax would be imposed upon us as an entity, cash available for distribution to unitholders would be reduced. Treatment of us as a corporation would result in a reduction in the anticipated cash flow and after-tax return to unitholders and therefore would likely result in a reduction in the value of the common units.

Our partnership agreement provides that if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for federal, state or local income tax purposes, then the minimum quarterly distribution amount and the target distribution amount will be adjusted to reflect the impact of that law on us.

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

The IRS may adopt positions that differ from our counsel's conclusions. It may be necessary to resort to administrative or court proceedings to sustain some or all of our counsel's conclusions or the positions we take. A court may not agree with some or all our counsel's conclusions or the positions we take. Any contest with the IRS may materially and adversely impact the market for our common units and the prices at which they trade. In addition, the costs of any contest with the IRS will be borne directly or indirectly by all of our unitholders, debt security holders and our general partner.

Table of Contents

Unitholders may be required to pay taxes on income from us even if they do not receive any cash distributions from us.

Unitholders may be required to pay federal income taxes and, in some cases, state, local and foreign income taxes on their share of our taxable income even if they receive no cash distributions from us. Unitholders may not receive cash distributions from us equal to their share of our taxable income or even the tax liability that results from the taxation of their share of our taxable income.

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

If our unitholders sell their common units, they will recognize gain or loss equal to the difference between the amount realized and their tax basis in those common units. Prior distributions in excess of the total net taxable income unitholders were allocated for a common unit, which decreased unitholder tax basis in that common unit, will, in effect, become taxable income to our unitholders if the common unit is sold at a price greater than their tax basis in that common unit, even if the price they receive is less than their original cost. A substantial portion of the amount realized, whether or not representing gain, may be ordinary income to our unitholders. Should the IRS successfully contest some positions we take, our unitholders could recognize more gain on the sale of units than would be the case under those positions, without the benefit of decreased income in prior years. In addition, if our unitholders sell their units, they may incur a tax liability in excess of the amount of cash they receive from the sale.

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

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

We treat a purchaser of our common units as having the same tax benefits without regard to the seller’s identity. The IRS may challenge this treatment, which could adversely affect the value of the common units.

Because we cannot match transferors and transferees of common units and because of other reasons, we have adopted depreciation positions that may not conform to all aspects of the Treasury regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to our unitholders. It also could affect the timing of these tax benefits or the amount of gain from the sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to our unitholders’ tax returns.

Unitholders may be subject to state, local and foreign taxes and return filing requirements as a result of investing in our common units.

In addition to federal income taxes, unitholders may be subject to other taxes, such as state, local and foreign income taxes, unincorporated business taxes and estate, inheritance, or intangible taxes that are imposed by the various jurisdictions in which we do business or own property. Unitholders may be required to file state, local and foreign income tax returns and pay state and local income taxes in some or all of the various jurisdictions in which we do business or own property and may be subject to penalties for failure to comply with those requirements. We own property and conduct business in Alabama, Arkansas, California, Georgia, Florida, Illinois, Louisiana, Mississippi, Nebraska, Texas and Utah. We may do business or own property in other states or foreign countries in the future. It is the unitholder's responsibility to file all federal, state, local and foreign tax returns. Our counsel has not rendered an opinion on the state, local or foreign tax consequences of an investment in our common units.

There are limits on the deductibility of our losses that may adversely affect our unitholders.

There are a number of limitations that may prevent unitholders from using their allocable share of our losses as a deduction against unrelated income. In cases when our unitholders are subject to the passive loss rules (generally, individuals and closely-held corporations), any losses generated by us will only be available to offset our future income and cannot be used to offset income from other activities, including other passive activities or investments. Unused losses may be deducted when the unitholder disposes of its entire investment in us in a fully taxable transaction with an unrelated party. A unitholder's share of our net passive income may be offset by unused losses from us carried over from prior years, but not by losses from other passive activities, including losses from other publicly traded partnerships. Other limitations that may further restrict the deductibility of our losses by a unitholder include the at-risk rules and the prohibition against loss allocations in excess of the unitholder's tax basis in its units.

Table of Contents

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

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

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

We will be considered to have terminated for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. Our termination would, among other things, result in the closing of our taxable year for all unitholders, which would result in us filing two tax returns for one fiscal year. For purposes of determining whether the 50% threshold is met, multiple sales of the same units are counted only once. Our termination could also result in a deferral of depreciation deductions allowable in computing our taxable income. In the case of a unitholder reporting on a taxable year other than a fiscal year ending December 31, the closing of our taxable year may also result in more than twelve months of our taxable income or loss being includable in his taxable income for the year of termination. Our termination currently would not affect our classification as a partnership for federal income tax purposes, but instead, we would be treated as a new partnership for tax purposes. If treated as a new partnership, we must make new tax elections and could be subject to penalties if we are unable to determine that a termination occurred. The IRS recently announced a relief procedure whereby, if a publicly traded partnership that has technically terminated requests and the IRS grants special relief, among other things, the partnership will be allowed to provide only a single Schedule K-1 to unitholders for the tax year in which the termination occurred.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The IRS may challenge this treatment, which could change the allocation of items of income, gain, loss and deduction among our unitholders.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The use of this proration method may not be permitted under existing Treasury regulations. Recently, however, the U.S. Treasury Department issued proposed Treasury regulations that provide a safe harbor pursuant to which publicly traded partnerships may use a similar monthly convention to allocate tax items among transferor and transferee unitholders. Nonetheless, the proposed Treasury regulations do not specifically authorize the use of the proration method we have adopted. Therefore, the use of this proration method may not be permitted under existing Treasury regulations, and, accordingly, our counsel is unable to opine as to the validity of this method. If the IRS were to challenge this method or new Treasury regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

A unitholder whose units are loaned to a “short seller” to cover a short sale of units may be considered as having disposed of those units. If so, he would no longer be treated for tax purposes as a partner with respect to those units during the period of the loan and may recognize gain or loss from the disposition.

Because a unitholder whose units are loaned to a “short seller” to cover a short sale of units may be considered as having disposed of the loaned units, he may no longer be treated for tax purposes as a partner with respect to those units during the period of the loan to the short seller and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan to the short seller, any of our income, gain, loss or deduction with respect to those units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those units could be fully taxable as ordinary income. Our counsel has not rendered an opinion regarding the treatment of a unitholder where common units are loaned to a short seller to cover a short sale of common units; therefore, unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller are urged to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their units.

Table of Contents

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

A description of our properties is contained in Item 1. Business.

We believe we have satisfactory title to our assets. Some of the easements, rights-of-way, permits, licenses or similar documents relating to the use of the properties that have been transferred to us in connection with our initial public offering and the assets we acquired in our acquisitions, required the consent of third parties, which in some cases is a governmental entity. We believe we have obtained sufficient third-party consents, permits and authorizations for the transfer of assets necessary for us to operate our business in all material respects. With respect to any third-party consents, permits or authorizations that have not been obtained, we believe the failure to obtain these consents, permits or authorizations will not have a material adverse effect on the operation of our business.

Title to our property may be subject to encumbrances, including liens in favor of our secured lender. We believe none of these encumbrances materially detract from the value of our properties or our interest in these properties, or materially interfere with their use in the operation of our business.

Item 3. Legal Proceedings

From time to time, we are subject to certain legal proceedings claims and disputes that arise in the ordinary course of our business. Although we cannot predict the outcomes of these legal proceedings, we do not believe these actions, in the aggregate, will have a material adverse impact on our financial position, results of operations or liquidity.

In addition to the foregoing, as a result of a routine inspection by the U.S. Coast Guard of our tug Martin Explorer at the Freeport Sulfur Dock Terminal in Tampa, Florida, we were informed that an investigation was commenced concerning a possible violation of the Act to Prevent Pollution from Ships, 33 USC 1901, et. seq., and the MARPOL Protocol 73/78 during the fourth quarter of 2007. We cooperated with the investigation and no formal charges, fines and/or penalties have been asserted against us. Counsel representing us in this matter has informed us that the investigation is now finished and the matter has been closed.

Item 4. Reserved

PART II

Item 5. Market for Our Common Equity, Related Unitholder Matters and Issuer Purchases of Equity Securities

Our common units are traded on the NASDAQ under the symbol “MMLP.” As of March 2, 2011 there were approximately 19 holders of record and approximately 16,468 beneficial owners of our common units. In addition, as of that date there were 889,444 subordinated units representing limited partner interests outstanding. All of the subordinated units are held by Martin Resource Management through a subsidiary. There is no established public trading market for our subordinated units. The following table sets forth the high and low closing sale prices of our common units for the periods indicated, based on the daily composite listing of stock transactions for the NASDAQ and cash distributions declared per common and subordinated units during those periods:

Fiscal 2010:

Quarters Ended	Common Units		Distributions Declared per Unit	
	High	Low	Common	Subordinated1
March 31, 2010	$34.25	$29.34	$0.750	$ —
June 30, 2010	$32.45	$27.00	$0.750	$ —
September 30, 2010	$33.87	$28.78	$0.750	$ —
December 31, 2010	$39.37	$32.85	$0.760	$ —

Table of Contents

Fiscal 2009:

Quarters Ended	Common Units		Distributions Declared per Unit	
	High	Low	Common	Subordinated1
March 31, 2009	$21.00	$14.89	$0.750	$ 0.750
June 30, 2009	$21.96	$17.33	$0.750	$ 0.750
September 30, 2009	$28.50	$20.70	$0.750	$ 0.750
December 31, 2009	$31.69	$26.02	$0.750	$ 0.750

1 All of our original 4,253,362 subordinated units which were issued upon the formation of the Partnership and subsequently converted into common units on a one-for-one basis received distributions prior to their conversion. The 889,444 subordinated units issued in connection with the acquisition of the Cross assets will not receive cash distributions until February 2012, the first distribution paid after they automatically convert into common units in November 2011.

On March 1, 2011, the last reported sales price of our common units as reported on the NASDAQ was $38.93 per unit.

In February 2011, in connection with our public offering of 1,874,500 common units our general partner contributed $1.5 million in cash to us in order to maintain its 2% general partner interest in us.

In August 2010, we completed a public offering of 1,000,000 common units. We used the net proceeds of $28.1 million to redeem from subsidiaries of Martin Resource Management an aggregate number of common units equal to the number of common units issued in the offering. As a result of these simultaneous transactions, our general partner was not required to contribute cash to us in order to maintain its 2% general partner interest in us since there was no net increase in the outstanding limited partner units.

In February 2010, in connection with our public offering of 1,650,000 common units, our general partner contributed $1.1 million in cash to us in order to maintain its 2% general partner interest in us.

Within 45 days after the end of each quarter, we distribute all of our available cash, as defined in our partnership agreement, to unitholders of record on the applicable record date. Until our current subordinated units convert into common units in November 2011, the subordinated units will not have the right to receive distributions of available cash from operating surplus .

Our general partner has broad discretion to establish cash reserves that it determines are necessary or appropriate to properly conduct our business. These can include cash reserves for future capital and maintenance expenditures, reserves to stabilize distributions of cash to the unitholders and our general partner, reserves to reduce debt, or, as necessary, reserves to comply with the terms of any of our agreements or obligations. Our distributions are effectively made 98% to unitholders and 2% to our general partner, subject to the payment of incentive distributions to our general partner if certain target cash distribution levels to common unitholders are achieved. Distributions to our general partner increase to 15%, 25% and 50% based on incremental distribution thresholds as set forth in our partnership agreement.

Our ability to distribute available cash is contractually restricted by the terms of our credit facility. Our credit facility contains covenants requiring us to maintain certain financial ratios. We are prohibited from making any distributions to unitholders if the distribution would cause a default or an event of default, or a default or an event of default exists, under our credit facility. Please read “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Description of Our Credit Facility.”

Item 6. Selected Financial Data

The following table sets forth selected financial data and other operating data of Martin Midstream Partners L.P. for the years ended December 31, 2010, 2009, 2008, 2007 and 2006 is derived from the audited consolidated financial statements of Martin Midstream Partners L.P.

Table of Contents

The following selected financial data are qualified by reference to and should be read in conjunction with our Consolidated and Combined Financial Statements and Notes thereto and "Management's Discussion and Analysis of Financial Condition and Results of Operations" included elsewhere in this document.

	2010	2009	2008	2007	2006
	(Dollars in thousands, except per unit amounts)				
Income Statement Data:					
Revenues	$912,118	$662,385	$1,246,444	$804,327	$576,384
Cost of product sold	693,902	457,259	1,013,526	618,689	459,170
Operating expenses	116,402	117,438	126,808	104,165	65,387
Selling, general, and administrative	21,118	19,775	19,062	13,918	10,977
Depreciation and amortization	40,656	39,506	34,893	26,323	17,597
Total costs and expenses	872,078	633,978	1,194,289	763,095	553,131
Other operating income	136	6,013	209	703	3,356
Operating income	40,176	34,420	52,364	41,935	26,609
Equity in earnings of unconsolidated entities	9,792	7,044	13,224	10,941	8,547
Interest expense	(33,716)	(18,995)	(21,433)	(15,125)	(12,466)
Debt prepayment premium	—	—	—	—	(1,160)
Other, net	287	326	801	405	713
Income before income taxes	16,539	22,795	44,956	38,156	22,243
Income taxes	517	592	1,398	5,595	—
Net income	$16,022	$22,203	$43,558	$32,561	$22,243
Net income per limited partner unit	$0.63	$1.17	$2.72	$1.67	$1.69
Weighted average limited partner units	17,525,089	14,680,807	14,529,826	14,018,799	12,602,000
Balance Sheet Data (at Period End):					
Total assets	$785,478	$685,939	$706,322	$656,604	$457,461
Due to affiliates	6,957	13,810	23,085	17,119	10,474
Long-term debt	372,862	304,372	295,000	225,000	174,021
Partner's capital (owner's equity)	274,806	264,951	246,379	246,765	198,525
Cash Flow Data:					
Net cash flow provided by (used in):					
Operating activities	37,518	47,592	86,340	61,209	39,317
Investing activities	(81,318)	(14,675)	(106,621)	(130,295)	(95,098)
Financing activities	49,224	(34,944)	24,151	69,896	52,991
Other Financial Data:					
Maintenance capital expenditures	4,653	7,601	17,998	11,955	12,391
Expansion capital expenditures	12,367	28,572	89,435	109,474	78,267
Total capital expenditures	$17,020	$36,173	$107,433	$121,429	$90,658

Cash dividends per common unit (in dollars)	$3.00	$3.00	$2.91	$2.60	$2.44

The following tables present our historical results of operations, the effect of including the results of the Cross assets which are included in our terminalling and storage segment and the revised total amounts included in our consolidated financial statements:

	Year Ended December 31, 2009		
	Historical Martin Midstream Partners LP	Cross Assets Results	Revised Total
	(Dollars in thousands, except per unit amounts)		
Revenues	$633,776	$28,609	$662,385
Costs and expenses:			
Cost of products sold (excluding depreciation and amortization)	457,259	—	457,259
Operating expenses	98,677	18,761	117,438
Selling, general and administrative	18,090	1,685	19,775
Depreciation and amortization	35,143	4,363	39,506
Total costs and expenses	609,169	24,809	633,978
Other operating income	6,160	(147)	6,013
Operating income	30,767	3,653	34,420
Equity in earnings of unconsolidated entities	7,044	—	7,044
Interest expense	(18,124)	(871)	(18,995)
Other, net	303	23	326
Net income before taxes	19,990	2,805	22,795
Income tax benefit (expense)	549	(1,141)	(592)
Net income	$20,539	$1,664	$22,203

	Year Ended December 31, 2008		
	Historical Martin Midstream Partners LP	Cross Assets Results	Revised Total
	(Dollars in thousands, except per unit amounts)		
Revenues	$1,213,958	$32,486	$1,246,444
Costs and expenses:			
Cost of products sold (excluding depreciation and amortization)	1,013,526	—	1,013,526
Operating expenses	102,894	23,914	126,808
Selling, general and administrative	16,939	2,123	19,062
Depreciation and amortization	31,218	3,675	34,893
Total costs and expenses	1,164,576	29,712	1,194289
Other operating income	209	—	209
Operating income	49,591	2,773	52,364
Equity in earnings of unconsolidated entities	13,224	—	13,224
Interest expense	(19,777)	(1,656)	(21,433)
Other, net	483	318	801
Net income before taxes	43,521	1,435	44,956
Income tax benefit (expense)	(711)	(687)	(1,398)
Net income	$42,810	$748	$43,558

	Year Ended December 31, 2007		
	Historical Martin Midstream Partners LP	Cross Assets Results	Revised Total
	(Dollars in thousands, except per unit amounts)		
Revenues	$765,822	$38,505	$804,327
Costs and expenses:			
Cost of products sold (excluding depreciation and amortization)	618,689	—	618,689
Operating expenses	83,533	20,632	104,165
Selling, general and administrative	11,985	1,933	13,918
Depreciation and amortization	23,442	2,881	26,323
Total costs and expenses	737,649	25,446	763,095
Other operating income	703	—	703
Operating income	28,876	13,059	41,935
Equity in earnings of unconsolidated entities	10,941	—	10,941
Interest expense	(14,533)	(592)	(15,125)
Other, net	299	106	405
Net income before taxes	25,583	12,573	38,156
Income tax benefit (expense)	(644)	(4,951)	(5,595)
Net income	$24,939	$7,622	$32,561

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

References in this annual report to “we,” “ours,” “us” or like terms when used in a historical context refer to the assets and operations of Martin Resource Management’s business contributed to us in connection with our initial public offering on November 6, 2002. References in this annual report to “Martin Resource Management” refers to Martin Resource Management Corporation and its subsidiaries, unless the context otherwise requires. You should read the following discussion of our financial condition and results of operations in conjunction with the consolidated financial statements and the notes thereto included elsewhere in this annual report. For more detailed information regarding the basis for presentation for the following information, you should read the notes to the consolidated financial statements included elsewhere in this annual report.

Forward-Looking Statements

This annual report on Form 10-K includes “forward-looking statements” within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. Statements included in this annual report that are not historical facts (including any statements concerning plans and objectives of management for future operations or economic performance, or assumptions or forecasts related thereto), are forward-looking statements. These statements can be identified by the use of forward-looking terminology including “forecast,” “may,” “believe,” “will,” “expect,” “anticipate,” “estimate,” “continue” or other similar words. These statements di future expectations, contain projections of results of operations or of financial condition or state other “forward-looking” information. We and our representatives may from time to time make other oral or written statements that are also forward-looking statements.

These forward-looking statements are made based upon management’s current plans, expectations, estimates, assumptions and beliefs concerning future events impacting us and therefore involve a number of risks and uncertainties. We caution that forward-looking statements are not guarantees and that actual results could differ materially from those expressed or implied in the forward-looking statements.

Table of Contents

Because these forward-looking statements involve risks and uncertainties, actual results could differ materially from those expressed or implied by these forward-looking statements for a number of important reasons, including those discussed above in "Item 1A. Risk Factors – Risks Related to our Business".

Overview

We are a publicly traded limited partnership with a diverse set of operations focused primarily in the United States Gulf Coast region. Our four primary business lines include:

- Terminalling and storage services for petroleum and by-products;
- Natural gas services;
- Sulfur and sulfur-based products gathering, processing, marketing, manufacturing and distribution; and
- Marine transportation services for petroleum products and by-products.

The petroleum products and by-products we gather, process, transport, store and market are produced primarily by major and independent oil and gas companies who often turn to third parties, such as us, for the transportation and disposition of these products. In addition to these major and independent oil and gas companies, our primary customers include independent refiners, large chemical companies, fertilizer manufacturers and other wholesale purchasers of these products. We generate the majority of our cash flow from fee-based contracts with these customers. Our location in the Gulf Coast region of the United States provides us strategic access to a major hub for petroleum refining, natural gas gathering and processing and support services for the exploration and production industry.

We were formed in 2002 by Martin Resource Management, a privately-held company whose initial predecessor was incorporated in 1951 as a supplier of products and services to drilling rig contractors. Since then, Martin Resource Management has expanded its operations through acquisitions and internal expansion initiatives as its management identified and capitalized on the needs of producers and purchasers of hydrocarbon products and by-products and other bulk liquids. As of March 2, 2011, Martin Resource Management owns an approximate 31.6% limited partnership interest in us. Furthermore, it owns and controls our general partner, which owns a 2.0% general partner interest and incentive distribution rights in us.

The historical operation of our business segments by Martin Resource Management provides us with several decades of experience and a demonstrated track record of customer service across our operations. Our current lines of business have been developed and systematically integrated over this period of more than 50 years, including natural gas services (1950s); sulfur (1960s); marine transportation (late 1980s) and terminalling and storage (early 1990s). This development of a diversified and integrated set of assets and operations has produced a complementary portfolio of midstream services that facilitates the maintenance of long-term customer relationships and encourages the development of new customer relationships.

2010 Developments and Subsequent Events

Global financial markets and economic conditions have been, and continue to be volatile. Numerous events have restricted current liquidity in the capital markets throughout the United States and around the world. One of the features driving investment in master limited partnerships, including us, has been the opportunity for distribution growth offered by the partnerships. Such distribution growth is a function of having access to liquidity in the financial markets used for incremental capital investment (development projects and acquisitions) to grow distributable cash flow. Growth opportunities have been, and may be further constrained by a lack of liquidity in the financial markets. During much of 2010 the financial markets were available to us. As such, we were able to issue senior unsecured long-term debt in the first quarter 2010 and equity in both the first and third quarters of 2010. Additionally, as discussed in the Subsequent Events section within this item, we were able to issue equity in February 2011 for the purpose of reducing outstanding indebtedness under our credit facility.

Conditions in our industry continued to be challenging throughout 2010. For example:

- The general decline in drilling activity by gas producers in our areas of operations in Northeast Texas which began during the fourth quarter of 2008 as a result of the global economic crisis continues. Several gas producers in our areas of operation have substantially reduced drilling activity during 2009 and 2010 as compared to their drilling levels during 2008.

- Coupled with the general decline in drilling activity is the federal government's enhanced safety regulations and inspection requirements as it relates to deep-water drilling in the Gulf of Mexico. On October 12, 2010, the United States Government lifted the moratorium on deep water permitting and drilling. However, these enhanced safety regulations and inspection requirements of the Bureau of Ocean Energy Management, Regulation, and Enforcement (BOEMRE) continue to provide uncertainty surrounding the requirements for and pace of issuance of permits on the Gulf of Mexico Outer Continental Shelf (OCS).

- The decline in the demand for marine transportation services based on decreased refinery production resulted in an oversupply of equipment which was partially offset by the marine transportation services required in the efforts to clean up the BP oil spill in the Gulf of Mexico.

Despite the reduced drilling activity and the decline in the demand for marine transportation services, we are positioning ourselves to benefit from a recovering economy. In particular:

- We adjusted our business strategy for 2009 and 2010 to focus on maximizing our liquidity, maintaining a stable asset base, and improving the profitability of our assets by increasing their utilization while controlling costs. We reduced our capital expenditures in 2009, but increased them in 2010 based on our capital raised in both the debt and equity markets during the year.

- We continue to evaluate opportunities to enter into commodity hedging transactions to further reduce our commodity price risk.

- We completed the disposition of certain non-strategic assets including the April 2009 sale of the Mont Belvieu Railcar Unloading Facility for $19.6 million, and we may consider marketing certain other non-strategic assets in the future.

- Our near-term financial focus is to ensure that we have appropriate levels of liquidity to fund our growth programs and potentially increase the distribution rate to our unitholders. The uncertain economic environment of recent years and ongoing litigation at Martin Resource Management created a challenge in obtaining such liquidity. However, in the past year we have had access to the capital markets and now have appropriate levels of liquidity and operating cash flows to adequately fund our growth.

Recent Acquisitions

Acquisition of the Darco Gathering System. On November 12, 2010, we, through our wholly owned subsidiary, Prism Gas, acquired approximately 20 miles of natural gas gathering pipeline and various equipment located in Harrison County, Texas for approximately $25.0 million. We financed this acquisition with borrowings under our revolving loan facility.

Acquisition by Waskom of the Harrison Pipeline System. On January 15, 2010, we, through Prism Gas, as 50% owner and the operator of Waskom Gas Processing Company (“WGPC”), through WGPC’s wholly owned subsidiary Waskom Midstream LLC, acquired from Crosstex North Texas Gathering, L.P., a 100% interest in approximately 62 miles of gathering pipeline, two 35 MMcfd dew point control plants and equipment referred to as the Harrison Pipeline System. Our share of the acquisition cost is approximately $20.0 million.

Other Developments

Public Offerings. On August 17, 2010, we completed a public offering of 1.0 million common units, resulting in net proceeds of approximately $28.1 million after payment of underwriters’ discounts. We used the net proceeds of $28.1 million to redeem from subsidiaries of Martin Resource Management an aggregate number of common units equal to the number of common units issued in the offering. Martin Resource Management reimbursed us for our payments of commissions and offering expenses. As a result of these transactions, our general partner was not required to contribute cash to us in conjunction with the issuance of these units in order to maintain its 2% general partner interest in us since there was no net increase in the outstanding limited partner units.

On February 8, 2010, we completed a public offering of 1,650,000 common units, resulting in net proceeds of $50.6 million, after payment of underwriters' discounts, commissions and offering expenses. Our general partner contributed $1.1 million in cash to us in conjunction with the issuance in order to maintain its 2% general partner interest in us. The net proceeds were used to pay down revolving debt under our credit facility.

Debt Financing Activities. Effective March 26, 2010, our credit facility was amended to (i) decrease the size of our aggregate facility from $350.0 million to $275.0 million, (ii) convert all term loans to revolving loans, (iii) extend the maturity date from November 9, 2012 to March 15, 2013, (iv) permit us to invest up to $40.0 million in our joint ventures, (v) eliminate the covenant that limits our ability to make capital expenditures, (vi) decrease the applicable interest rate margin on committed revolver loans, (vii) limit our ability to make future acquisitions and (viii) adjust the financial covenants. For a more detailed discussion regarding our credit facility, see "Description of Our Long-Term Debt—Credit Facility" within this Item.

Table of Contents

On March 26, 2010, we completed a private placement of $200.0 million in aggregate principal amount of 8.875% senior unsecured notes due 2018 (“2018 Notes”) to qualified institutional buyers under Rule 144A. We received proceeds of approximately $197.2 million, after deducting initial purchasers’ discounts and the expenses of the private placement. The proceeds were primarily used to repay borrowings under the Partnership’s revolving credit facility. Pursuant to the terms of a registration rights agreement entered into in connection with the offering of the 2018 Notes, we filed an exchange offer registration statement with the SEC on September 16, 2010 with respect to an offer to exchange the 2018 Notes for registered notes with substantially identical terms. The registration statement was declared effective by the SEC and the exchange offer was completed in the fourth quarter of 2010.

Subsequent Events

Public Offering. On February 9, 2011, we completed a public offering of 1,874,500 common units, our general partner contributed $1.5 million in cash to in order to maintain its 2% general partner interest in us

Acquisition of Certain Terminalling Assets. On January 31, 2011, we acquired 13 shore-based marine terminalling facilities, one specialty terminalling facility and certain terminalling related assets from Martin Resource Management for $36.5 million. The net book value of the acquired assets was recorded in property, plant and equipment. These assets are located across the Louisiana Gulf Coast. This acquisition was funded by borrowings under our revolving loan facility.

Quarterly Distribution. On January 24, 2011, we declared a quarterly cash distribution of $0.76 per common unit for the fourth quarter of 2010, or $3.04 per common unit on an annualized basis, to be paid on February 14, 2011 to unitholders of record as of February 3, 2011, reflecting a $0.01 increase over the quarterly distribution paid in respect to the third quarter of 2010.

Critical Accounting Policies

Our discussion and analysis of our financial condition and results of operations are based on the historical consolidated and condensed financial statements included elsewhere herein. We prepared these financial statements in conformity with generally accepted accounting principles. The preparation of these financial statements required us to make estimates and assumptions that affect the reported amounts of assets and liabilities at the dates of the financial statements and the reported amounts of revenues and expenses during the reporting periods. We based our estimates on historical experience and on various other assumptions we believe to be reasonable under the circumstances. Our results may differ from these estimates. Currently, we believe that our accounting policies do not require us to make estimates using assumptions about matters that are highly uncertain. However, we have described below the critical accounting policies that we believe could impact our consolidated and condensed financial statements most significantly.

You should also read Note 2, “Significant Accounting Policies” in Notes to Consolidated Financial Statements contained in this annual report on Form 10-K. Some of the more significant estimates in these financial statements include the amount of the allowance for doubtful accounts receivable and the determination of the fair value of our reporting units as it relates to our annual goodwill evaluation.

Derivatives

All derivatives and hedging instruments are included on the balance sheet as an asset or liability measured at fair value and changes in fair value are recognized currently in earnings unless specific hedge accounting criteria are met. If a derivative qualifies for hedge accounting, changes in the fair value can be offset against the change in the fair value of the hedged item through earnings or recognized in other comprehensive income until such time as the hedged item is recognized in earnings. Our hedging policy allows us to use hedge accounting for financial transactions that are designated as hedges. Derivative instruments not designated as hedges or hedges that become ineffective are being marked to market with all market value adjustments being recorded in the consolidated statements of operations. As of December 31, 2010, we have designated a portion of our derivative instruments as qualifying cash flow hedges. Fair value changes for these hedges have been recorded in other comprehensive income as a component of partners' capital.

Product Exchanges

We enter into product exchange agreements with third parties whereby we agree to exchange natural gas liquids ("NGLs") and sulfur with third parties. We record the balance of exchange products due to other companies under these agreements at quoted market product prices and the balance of exchange products due from other companies at the lower of cost or market. Cost is determined using the first-in, first-out method. Revenue and costs related to product exchanges are recorded on a gross basis.

Table of Contents

Revenue Recognition

Revenue for our four operating segments is recognized as follows:

Terminalling and storage – Revenue is recognized for storage contracts based on the contracted monthly tank fixed fee. For throughput contracts, revenue is recognized based on the volume moved through our terminals at the contracted rate. For our tolling agreement, revenue is recognized based on the contracted monthly reservation fee and throughput volumes moved through the facility. When lubricants and drilling fluids are sold by truck, revenue is recognized upon delivering product to the customers as title to the product transfers when the customer physically receives the product.

Natural gas services – Natural gas gathering and processing revenues are recognized when title passes or service is performed. NGL distribution revenue is recognized when product is delivered by truck to our NGL customers, which occurs when the customer physically receives the product. When product is sold in storage, or by pipeline, we recognize NGL distribution revenue when the customer receives the product from either the storage facility or pipeline.

Sulfur services – Revenue is recognized when the customer takes title to the product at our plant or the customer facility.

Marine transportation – Revenue is recognized for contracted trips upon completion of the particular trip. For time charters, revenue is recognized based on a per day rate.

Equity Method Investments

We use the equity method of accounting for investments in unconsolidated entities where the ability to exercise significant influence over such entities exists. Investments in unconsolidated entities consist of capital contributions and advances plus our share of accumulated earnings as of the entities' latest fiscal year-ends, less capital withdrawals and distributions. Investments in excess of the underlying net assets of equity method investees, specifically identifiable to property, plant and equipment, are amortized over the useful life of the related assets. Excess investment representing equity method goodwill is not amortized but is evaluated for impairment, annually. This goodwill is not subject to amortization and is accounted for as a component of the investment. Equity method investments are subject to impairment evaluation. No portion of the net income from these entities is included in our operating income.

We own an unconsolidated 50% of the ownership interests in Waskom Gas Processing Company ("Waskom"), Matagorda Offshore Gathering System ("Matagorda") and Panther Interstate Pipeline Energy LLC ("PIPE"). Each of these interests is accounted for under the equity method of accounting.

Goodwill

Goodwill is subject to a fair-value based impairment test on an annual basis. We are required to identify our reporting units and determine the carrying value of each reporting unit by assigning the assets and liabilities, including the existing goodwill and intangible assets. We are required to determine the fair value of each reporting unit and compare it to the carrying amount of the reporting unit. To the extent the carrying amount of a reporting unit exceeds the fair value of the reporting unit, we would be required to perform the second step of the impairment test, as this is an indication that the reporting unit goodwill may be impaired.

All four of our “reporting units”, terminalling and storage, marine transportation, natural gas services and sulfur services, contain goodwill.

We have performed the annual impairment tests as of September 30, 2010, September 30, 2009, and September 30, 2008, and we have determined fair value in each reporting unit based on the weighted average of three valuation techniques: (i) the discounted cash flow method, (ii) the guideline public company method, and (iii) the guideline transaction method. At September 30, 2010, 2009 and 2008 the estimated fair value of each of our four reporting units was in excess of its carrying value resulting in no impairment.

As a result of the deterioration in the overall stock market subsequent to September 30, 2008 and the decline in our unit price, we reviewed specific factors, as outlined in under certain provisions of ASC 350-20, to determine if we had a trigging event that required us to test our goodwill for impairment as of December 31, 2008. These factors included whether there have been any significant fundamental changes since our annual impairment test to (i) our business as a whole or to the reporting units, including regulatory changes, (ii) our level of operating cash flows, (iii) our expectation of future levels of operating cash flows, (iv) our executive management team and (v) the carrying value of our other long-lived assets. While these factors did not indicate a triggering event occurred, our unit price fell to a point by December 31, 2008, that resulted in our total market capitalization being less than our partner’s equity. We determined this to be a triggering event requiring us to perform an impairment test as of December 31, 2008. As a result of our goodwill impairment test for each of the four reporting units as of December 31, 2008, no impairment was determined to exist.

No such triggering events occurred that would cause us to perform an impairment test at either December 31, 2010 or 2009.

Significant changes in these estimates and assumptions could materially affect the determination of fair value for each reporting unit which could give rise to future impairment. Changes to these estimates and assumptions can include, but may not be limited to, varying commodity prices, volume changes and operating costs due to market conditions and/or alternative providers of services.

Environmental Liabilities and Litigation

We have not historically experienced circumstances requiring us to account for environmental remediation obligations. If such circumstances arise, we would estimate remediation obligations utilizing a remediation feasibility study and any other related environmental studies that we may elect to perform. We would record changes to our estimated environmental liability as circumstances change or events occur, such as the issuance of revised orders by governmental bodies or court or other judicial orders and our evaluation of the likelihood and amount of the related eventual liability.

Because the outcomes of both contingent liabilities and litigation are difficult to predict, when accounting for these situations, significant management judgment is required. Amounts paid for contingent liabilities and litigation have not had a materially adverse effect on our operations or financial condition and we do not anticipate they will in the future.

Allowance for Doubtful Accounts

In evaluating the collectability of our accounts receivable, we assess a number of factors, including a specific customer’s ability to meet its financial obligations to us, the length of time the receivable has been past due and historical collection experience. Based on these assessments, we record specific and general reserves for bad debts to reduce the related receivables to the amount we ultimately expect to collect from customers.

Our management closely monitors potentially uncollectible accounts. Estimates of uncollectible amounts are revised each period, and changes are recorded in the period they become known. If there is a deterioration of a major customer’s creditworthiness or actual defaults are higher than the historical experience, management’s estimates of the recoverability of amounts due us could potentially be adversely affected. These charges have not had a materially adverse effect on our operations or financial condition.

Asset Retirement Obligation

We recognize and measure our asset and conditional asset retirement obligations and the associated asset retirement cost upon acquisition of the related asset and based upon the estimate of the cost to settle the obligation at its anticipated future date. The obligation is accreted to its estimated future value and the asset retirement cost is depreciated over the estimated life of the asset.

Estimates of future asset retirement obligations include significant management judgment and are based on projected future retirement costs. Such costs could differ significantly when they are incurred. Revisions to estimated asset retirement obligations can result from changes in retirement cost estimates due to surface repair, and labor and material costs, revisions to estimated inflation rates and changes in the estimated timing of abandonment. For example, the Company does not have access to natural gas reserves information related to our gathering systems to estimate when abandonment will occur.

- 53 -

Table of Contents

Our Relationship with Martin Resource Management

Martin Resource Management directs our business operations through its ownership and control of our general partner and under an omnibus agreement. In addition to the direct expenses, under the omnibus agreement, we are required to reimburse Martin Resource Management for indirect general and administrative and corporate overhead expenses. For the years ended December 31, 2010, 2009 and 2008, the Conflicts Committee of our general partner approved reimbursement amounts of $3.8, $3.5 and $2.9 million, respectively, reflecting our allocable share of such expenses. The Conflicts Committee will review and approve future adjustments in the reimbursement amount for indirect expenses, if any, annually.

We are required to reimburse Martin Resource Management for all direct expenses it incurs or payments it makes on our behalf or in connection with the operation of our business. Martin Resource Management also licenses certain of its trademarks and trade names to us under this omnibus agreement.

We are both an important supplier to and customer of Martin Resource Management. Among other things, we sell sulfuric acid and provide marine transportation and terminalling and storage services to Martin Resource Management. We purchase land transportation services, underground storage services, sulfuric acid and marine fuel from Martin Resource Management. All of these services and goods are purchased and sold pursuant to the terms of a number of agreements between us and Martin Resource Management.

For a more comprehensive discussion concerning the omnibus agreement and the other agreements that we have entered into with Martin Resource Management, please see "Item 13. Certain Relationships and Related Transactions, and Director Independence – Agreements."

Results of Operations

The results of operations for the twelve months ended December 31, 2010, 2009 and 2008 have been derived from our consolidated financial statements.

We evaluate segment performance on the basis of operating income, which is derived by subtracting cost of products sold, operating expenses, selling, general and administrative expenses, and depreciation and amortization expense from revenues. The following table sets forth our operating revenues and operating income by segment for the twelve months ended December 31, 2010, 2009 and 2008.

	Operating Revenues	Revenues Intersegment Eliminations	Operating Revenues after Eliminations	Operating Income (loss)	Operating Income Intersegment Eliminations	Operating Income (loss) after Eliminations
			(In thousands)			
Year ended December 31, 2010:						
Terminalling and storage	$119,270	$ (4,354)	$ 114,916	$16,032	$ (1,776)	$ 14,256
Natural gas services	554,482	—	554,482	4,652	964	5,616
Sulfur services	165,078	—	165,078	15,886	4,280	20,166
Marine transportation	82,635	(4,993)	77,642	9,992	(3,468)	6,524
Indirect selling, general and administrative	—	—	—	(6,386)	—	(6,386)
Total	$921,465	$ (9,347)	$ 912,118	$40,176	$ —	$ 40,176

Year ended December 31, 2009:						
Terminalling and storage	$109,513	$ (4,219)	$ 105,294	$20,231	$ (2,332)	$ 17,899
Natural gas services	408,989	(7)	408,982	4,880	786	5,666
Sulfur services	79,631	(2)	79,629	9,575	4,201	13,776
Marine transportation	72,103	(3,623)	68,480	5,811	(2,655)	3,156
Indirect selling, general and administrative	—	—	—	(6,077)	—	(6,077)
Total	$670,236	$ (7,851)	$ 662,385	$34,420	$ —	$ 34,420
Year ended December 31, 2008:						
Terminalling and storage	$122,960	$ (4,189)	$ 118,771	$15,034	$ (3,635)	$ 11,399
Natural gas services	679,375	—	679,375	2,780	945	3,725
Sulfur services	372,987	(1,038)	371,949	31,956	5,224	37,180
Marine transportation	80,059	(3,710)	76,349	8,104	(2,534)	5,570
Indirect selling, general and administrative	—	—	—	(5,510)	—	(5,510)
Total	$1,255,381	$ (8,937)	$ 1,246,444	$52,364	$ —	$ 52,364

Our results of operations are discussed on a comparative basis below. There are certain items of income and expense which we do not allocate on a segment basis. These items, including equity in earnings (loss) of unconsolidated entities, interest expense, and indirect selling, general and administrative expenses, are discussed after the comparative discussion of our results within each segment.

Table of Contents

Year Ended December 31, 2010 Compared to the Year Ended December 31, 2009

Our total revenues before eliminations were $921.5 million for the year ended December 31, 2010 compared to $670.2 million for the year ended December 31, 2009, an increase of $251.3 million, or 37%. Our operating income before eliminations was $40.2 million for the year ended December 31, 2010 compared to $34.4 million for the year ended December 31, 2009, an increase of $5.8 million, or 17%.

The results of operations are described in greater detail on a segment basis below.

Terminalling and Storage Segment

The following table summarizes our results of operations in our terminalling and storage segment.

	Years Ended December 31,	
	2010	2009
	(In thousands)	
Revenues:		
Services	$ 71,471	$ 73,885
Products	47,799	35,628
Total Revenues	119,270	109,513
Cost of products sold	44,549	31,331
Operating expenses	41,857	45,783
Selling, general and administrative expenses	426	1,955
Depreciation and amortization	16,650	15,717
	15,788	14,727
Other operating income (loss)	244	5,504
Operating income	$ 16,032	$ 20,231

Revenues. Our terminalling and storage revenues increased $9.8 million, or 9%, for the year ended December 31, 2010 compared to the year ended December 31, 2009. Service revenue decreased $2.4 million compared to the prior year period. This decrease is primarily due to the historical Cross refining margin included in the recast 2009 historical revenues exceeding the contractual tolling fee for feedstock processing received in 2010 of $4.7 million. This decrease was offset by an increase in activities at terminals of $2.3 million. Product revenue increased $12.2 million compared to the prior year period. Of this increase, $10.1 million was due to a 13% increase in average selling price and an 18% increase in sales volumes at our Mega Lubricants facility. Additionally, $7.5 million of this increase was due to the conversion of a consigned product delivery agreement with one of our customers to a buy/sell product delivery agreement during the third quarter of 2010. These increases were partially offset by a $5.4 million decrease due to the sale of our traditional lubricant business including inventory to Martin Resource Management in April 2009 in return for a service fee for lubricant volumes moved through our terminals.

Cost of products sold. Our cost of products sold increased $13.2 million, or 42% for the year ended December 31, 2010 compared to the year ended December 31, 2009. Of this increase, $10.1 million was due to an 18% increase in average cost of product and a 18% increase in sales volumes at our Mega Lubricants facility and $6.7 million of this increase was due to the conversion of a consigned product delivery agreement with one of our customers to a buy/sell product delivery agreement during the third quarter of 2010. The remaining $1.0 million increase was due to the increase in consigned marine delivery expenses. These increases were partially offset by a $4.6 million decrease due to the sale of our traditional lubricant business including inventory to Martin Resource Management in April 2009 in return for a service fee for lubricant volumes moved through our terminals

Operating expenses. Operating expenses decreased $3.9 million, or 9%, for the year ended December 31, 2010 compared to the year ended December 31, 2009. This decrease was primarily the result of a reduction of the historical level of expenses attributable to the Cross assets of $4.6 million. This decrease was offset by an increase in salaries and burden of $0.7 million.

Selling, general and administrative expenses. Selling, general and administrative expenses decreased $1.5 million, or 78% for the year ended December 31, 2010 compared to the year ended December 31, 2009. This decrease was primarily a result of the historical level of expenses attributable to the Cross assets.

Table of Contents

Depreciation and amortization. Depreciation and amortization increased $0.9 million, or 6%, for the year ended December 31, 2010 compared to the year ended December 31, 2009. This increase was primarily a result of our recent acquisitions and capital expenditures.

Other operating income (loss). Other operating income for the year ended December 31, 2010 consisted primarily of gains and losses on the disposal of assets. Other operating income for the year ended December 31, 2009 consisted primarily of a gain on the sale of our Mont Belvieu terminal on April 30, 2009.

In summary, terminalling and storage operating income decreased $4.2 million, or 21%, for the year ended December 31, 2010 compared to the year ended December 31, 2009.

Natural Gas Services Segment

The following table summarizes our results of operations in our natural gas services segment.

	Years Ended December 31,	
	2010	2009
	(In thousands)	
Revenues:		
NGLs	$ 501,919	$ 384,124
Natural gas	46,812	20,334
Non-cash mark to market and impairment adjustments of commodity derivatives	253	(2,490)
Gain (loss) on cash settlements of commodity derivatives	582	3,273
Other operating fees	4,916	3,748
Total revenues	554,482	408,989
Cost of products sold:		
NGLs	482,231	364,350
Natural gas	46,187	19,261
Total cost of products sold	528,418	383,611
Operating expenses	7,689	8,627
Selling, general and administrative expenses	8,588	7,332
Depreciation and amortization	5,023	4,527
	4,764	4,892
Other operating income	(112)	(12)
Operating income	$ 4,652	$ 4,880
NGLs Volumes (Bbls)	9,730	9,880
Natural Gas Volumes (Mmbtu)	11,390	6,155
*Information above does not include activities relating to Waskom, PIPE, Matagorda and BCP investments		
Equity in Earnings of Unconsolidated Entities	$ 9,792	$ 7,044
Waskom:		
Plant Inlet Volumes (MMcfd)	281	243

Frac Volumes (Bbls/d)	9,691	10,034

Revenues. Our natural gas services revenues increased $145.5 million, or 36% for the year ended December 31, 2010 compared to the year ended December 31, 2009 primarily due to higher commodity prices.

For the year ended December 31, 2010, NGL revenues increased $117.8 million, or 31% and natural gas revenues increased $26.5 million, or 130%. During 2010, our NGL average sales price per barrel increased $12.71 or 33% and our natural gas average sales price per Mmbtu increased $0.81, or 24% compared to the same period in 2009. NGL sales volumes for the year remained relatively consistent and natural gas volumes increased 85% compared to the same period of 2009. The increase in natural gas volumes is primarily due to the Waskom plant shutdown in second quarter 2009 and the acquisition by Waskom Midstream LLC of the Harrison Gathering system in first quarter 2010.

Table of Contents

Our natural gas services segment utilizes derivative instruments to manage the risk of fluctuations in market prices for its anticipated sales of natural gas, condensate and NGLs. This activity is referred to as price risk management. For the year ended December 31, 2010, 44% of our total natural gas volumes and 41% of our total NGL volumes were hedged as compared to 54% and 35%, respectively in 2009. The impact of price risk management and marketing activities increased total natural gas and NGL revenues $0.8 million for 2010 compared to an increase of $0.8 million in the same period of 2009.

Costs of product sold. Our cost of products increased $144.8 million, or 38%, for the year ended December 31, 2010 compared to the same period in 2009. Of the increase, $117.9 million relates to NGLs and $26.9 million relates to natural gas. Our NGL per barrel margins remained relatively consistent compared to the same period in 2009. The percentage increase relating to natural gas cost of products sold is greater than the percentage increase in natural gas revenues which caused our Mmbtu margins to decrease by 68%. This is primarily a result of operational issues whereby certain gas volumes are not currently being processed resulting in lower margins.

Operating expenses. Operating expenses decreased $0.9 million, or 11% for the year ended December 31, 2010 compared to the same period of 2009. This decrease was primarily a result of the Marshall Pipeline lease being assigned to Waskom Gas Processing in 2010 ($0.6 million). In addition, we saw a decrease in large compressor maintenance $0.3 million in 2010 as compared to 2009.

Selling, general and administrative expenses. Selling, general and administrative expenses increased $1.3 million, or 17% for the year ended December 31, 2010 compared to the same period of 2009. This increase was primarily a result of increased acquisition costs associated with the Waskom Midstream LLC acquisition ($1.0 million), offset by a reduction in audit related expenses for Waskom Gas Processing Company ($0.2 million). Additionally, the increase is attributed to the write-off of an uncollectible customer receivable ($0.5 million).

Depreciation and amortization. Depreciation and amortization increased $0.5 million, or 11%, for the year ended December 31, 2010 compared to the same period of 2009. This increase was primarily a result of normal capital expenditure activity during the current year.

In summary, our natural gas services operating income decreased $0.2 million, or 5%, for the year ended December 31, 2010 compared to the year ended December 31, 2009.

Sulfur Services Segment

The following table summarizes our results of operations in our sulfur services segment.

	Years Ended December 31,	
	2010	2009
	(In thousands)	
Revenues	$ 165,078	$ 79,631
Cost of products sold	122,483	43,748
Operating expenses	17,013	17,113
Selling, general and administrative expenses	3,422	3,449
Depreciation and amortization	6,262	6,151
	15,898	9,170
Other operating income	(12)	405
Operating income	$ 15,886	$ 9,575
Sulfur (long tons)	1,129.2	1,107.5

Fertilizer (long tons)	274.9	238.0
Sulfur Services Volumes (long tons)	1,404.1	1,345.5

Revenues. Our sulfur services revenues increased $85.4 million, or 107%, for the year ended December 31, 2010 compared to the year ended December 31, 2009. This increase was a result of higher market prices in 2010 compared to 2009.

Cost of products sold. Our cost of products sold increased $78.8 million, or 180%, for the year ended December 31, 2010 compared to the year ended December 31, 2009. This increase was directly related to the increased price of our raw materials in 2010 compared to 2009. Our overall gross margin per ton increased from $26.66 in 2009 to $30.34 in 2010.

Table of Contents

Operating expenses. Our operating expenses decreased $0.1 million, or 1%, for the year ended December 31, 2010 compared to the year ended December 31, 2009. This decrease was a result of decreased costs relating to fuel prices for marine transportation of our sulfur products.

Selling, general, and administrative expenses. Our selling, general, and administrative expenses increased less than $0.1 million, or 1%, for the year ended December 31, 2010 compared to the year ended December 31, 2009.

Depreciation and amortization. Depreciation and amortization increased $0.1 million, or 2%, for the year ended December 31, 2010 compared to the year ended December 31, 2009. This increase was primarily a result of normal capital expenditure activity during the current year.

In summary, our sulfur services operating income increased $6.3 million, or 66%, for the year ended December 31, 2010 compared to the year ended December 31, 2009.

Marine Transportation Segment

The following table summarizes our results of operations in our marine transportation segment.

	Years Ended December 31,	
	2010	2009
	(In thousands)	
Revenues	$ 82,635	$ 72,103
Operating expenses	57,642	52,335
Selling, general and administrative expenses	2,296	962
Depreciation and amortization	12,721	13,111
	9,976	5,695
Other operating income	16	116
Operating income	$ 9,992	$ 5,811

Revenues. Our marine transportation revenues increased $10.5 million, or 15%, for the year ended December 31, 2010 compared to the year ended December 31, 2009. Our offshore revenues increased $7.7 million primarily due to increased utilization of the offshore fleet in 2010. Our inland marine operations increased $2.8 million primarily due to an increase in inland freight revenue of $1.5 million. This increase was primarily a result of an increased utilization of the inland fleet, which was offset by decreased day rates in 2010. The remaining $1.3 million increase was due to an increase in ancillary revenues which consisted primarily of fuel and tankerman services.

Operating expenses. Operating expenses increased $5.3 million, or 10%, for the year ended December 31, 2010 compared to the year ended December 31, 2009. This was primarily a result of an increase in barge leases of $4.6 million and an increase in wages and burden costs of $1.1 million. These increases were offset by a decrease in repairs and maintenance expenses of $0.7 million.

Selling, general and administrative expenses. Selling, general and administrative expenses increased $1.3 million, or 139% for the year ended December 31, 2010 compared to the year ended December 31, 2009. This increase was primarily a result of bad debt in 2010.

Depreciation and amortization. Depreciation and amortization decreased $0.4 million, or 3%, for the year ended December 31, 2010 compared to the year ended December 31, 2009. This decrease was primarily a result of equipment disposals offset by capital expenditures made in the last 12 months.

Other operating income. Other operating income for the year ended December 31, 2010 and the year ended December 31, 2009 consisted of gains and losses on the disposal of assets.

In summary, our marine transportation operating income increased $4.2 million, or 72%, for the year ended December 31, 2010 compared to the year ended December 31, 2009.

Equity in Earnings of Unconsolidated Entities

For the years ended December 31, 2010 and 2009, equity in earnings of unconsolidated entities relates to our unconsolidated interests in Waskom Gas Processing Company (“Waskom”), Matagorda, PIPE and BCP. With respect to BCP, the lease contract terminated in June 2009, and, as such, the investment was fully amortized as of June 30, 2009.

Table of Contents

Equity in earnings of unconsolidated entities was $9.8 million for the year ended December 31, 2010, compared to $7.0 million for the year ended December 31, 2009, an increase of $2.8 million. This increase is a result of several factors including the acquisition by Waskom Midstream LLC of the Harrison Gathering system on January 1, 2010 and the Waskom plant and fractionator expansion completed at the end of the second quarter of 2009.

Interest Expense

Our interest expense for all operations was $33.8 million for 2010 compared to $19.0 million for 2009, an increase of $14.8 million, or 78%. This increase was primarily due to an increase in average debt outstanding and an increase in the average interest rates paid on the indebtedness throughout 2010 compared to 2009.

Indirect Selling, General and Administrative Expenses

Indirect selling, general and administrative expenses were $6.4 million for 2010 compared to $6.1 million for 2009, an increase of $0.3 million or 5%.

Martin Resource Management allocated to us a portion of its indirect selling, general and administrative expenses for services such as accounting, treasury, clerical billing, information technology, administration of insurance, engineering, general office expense and employee benefit plans and other general corporate overhead functions we share with Martin Resource Management retained businesses. This allocation is based on the percentage of time spent by Martin Resource Management personnel that provide such centralized services. Generally accepted accounting principles also permit other methods for allocation of these expenses, such as basing the allocation on the percentage of revenues contributed by a segment. The allocation of these expenses between Martin Resource Management and us is subject to a number of judgments and estimates, regardless of the method used. We can provide no assurances that our method of allocation, in the past or in the future, is or will be the most accurate or appropriate method of allocation these expenses. Other methods could result in a higher allocation of selling, general and administrative expense to us, which would reduce our net income.

In addition to the direct expenses, under the omnibus agreement, we are required to reimburse Martin Resource Management for indirect general and administrative and corporate overhead expenses. For the years ended December 31, 2010 and 2009, the Conflicts Committee of our general partner approved reimbursement amounts of $3.8 and $3.5 million, respectively, reflecting our allocable share of such expenses. The Conflicts Committee will review and approve future adjustments in the reimbursement amount for indirect expenses, if any, annually.

Year Ended December 31, 2009 Compared to the Year Ended December 31, 2008

Our total revenues before eliminations were $670.2 million for the year ended December 31, 2009 compared to $1,255.4 million for the year ended December 31, 2008, a decrease of $585.2 million, or 47%. Our operating income before eliminations was $34.4 million for the year ended December 31, 2009 compared to $52.4 million for the year ended December 31, 2008, a decrease of $18.0 million, or 34%.

The results of operations are described in greater detail on a segment basis below.

Terminalling and Storage Segment

The following table summarizes our results of operations in our terminalling and storage segment.

	Years Ended December 31,

	2009	2008
	(In thousands)	
Revenues:		
Services	$73,885	$72,604
Products	35,628	50,356
Total Revenues	109,513	122,960
Cost of products sold	31,331	42,721
Operating expenses	45,783	50,001
Selling, general and administrative expenses	1,955	2,243
Depreciation and amortization	15,717	12,947
	14,727	15,048
Other operating income (loss)	5,504	(14)
Operating income	$20,231	$15,034

Table of Contents

Revenues. Our terminalling and storage revenues decreased $13.4 million, or 11%, for the year ended December 31, 2009 compared to the year ended December 31, 2008. Service revenue accounted for a $1.3 million increase offset by a $14.7 million decrease in lubricant product sales. The service revenue increase was primarily a result of new agreements entered into in 2008 and 2009, including a new lubricant terminalling fee of $5.3 million. This service revenue increase was offset by decreased activity at our terminals of $2.4 million, decreased revenues from the Cross assets of $1.2 million, and lost revenues due to the sale of our Mont Belvieu terminal of $0.4 million. Of the $14.7 million lubricant product sales decrease, $12.6 million was due to the sale of our traditional lubricants business, including inventory, to Martin Resource Management in April 2009 in return for a service fee for lubricant volumes moved through our terminals. The remaining $2.1 million decrease is due to a 13% decrease in average selling price offset by a 7% increase in sales volumes at our Mega Lubricant facility.

Cost of products sold. Our cost of products sold decreased $11.4 million, or 27% for the year ended December 31, 2009 compared to the year ended December 31, 2008. This decrease was primarily due to the sale of our traditional lubricants business, including inventory to Martin Resource Management in April 2009 in return for a service fee for lubricant volumes moved through our terminals.

Operating expenses. Operating expenses decreased $4.2 million, or 8%, for the year ended December 31, 2009 compared to the year ended December 31, 2008. This decrease was a result of a $3.2 million decrease from the Cross assets, a $1.1 million decreases in hurricane expenses that were recorded in 2008, and a decrease in utility cost of $0.5 million. These decreases were offset by an increase in salaries and burden of $0.3 million and product hauling costs of $0.3 million.

Selling, general and administrative expenses. Selling, general & administrative expenses decreased $0.3 million, or 13% for the year ended December 31, 2009 compared to the year ended December 31, 2008. This decrease was primarily due to the Cross assets.

Depreciation and amortization. Depreciation and amortization increased $2.8 million, or 21%, for the year ended December 31, 2009 compared to the year ended December 31, 2008. This increase was primarily a result of our recent acquisitions and capital expenditures.

Other operating income (loss). Other operating income for the year ended December 31, 2009 consisted primarily of a gain on the sale of our Mont Belvieu terminal on April 30, 2009.

In summary, terminalling and storage operating income increased $5.2 million, or 35%, for the years ended December 31, 2009 and 2008.

Natural Gas Services Segment

The following table summarizes our results of operations in our natural gas services segment.

	Years Ended December 31,	
	2009	2008
	(In thousands)	
Revenues:		
NGLs	$384,124	$615,966
Natural gas	20,334	59,346
Non-cash mark to market and impairment adjustments of commodity derivatives	(2,490)	4,930
Gain (loss) on cash settlements of commodity derivatives	3,273	(3,932)

Other operating fees	3,748	3,065
Total revenues	408,989	679,375
Cost of products sold:		
NGLs	364,350	599,835
Natural gas	19,261	58,771
Total cost of products sold	383,611	658,606
Operating expenses	8,627	8,633
Selling, general and administrative expenses	7,332	5,292
Depreciation and amortization	4,527	4,067
	4,892	2,777
Other operating income	(12)	3
Operating income	$4,880	$2,780
NGLs Volumes (Bbls)	9,880	8,794
Natural Gas Volumes (Mmbtu)	6,155	7,267
*Information above does not include activities relating to Waskom, PIPE, Matagorda and BCP investments		
Equity in Earnings of Unconsolidated Entities	$7,044	$13,224
Waskom:		
Plant Inlet Volumes (MMcfd)	243	257
Frac Volumes (Bbls/d)	10,034	10,542

Revenues. Our natural gas services revenues decreased $270.4 million, or 40% for the year ended December 31, 2009 compared to the year ended December 31, 2008 primarily due to lower commodity prices.

For the year ended December 31, 2009, NGL revenues decreased $231.8 million, or 38% and natural gas revenues decreased $39.0 million, or 66%. During 2009, our NGL average sales price per barrel decreased $31.17 or 45% and our natural gas average sales price per Mmbtu decreased $4.86, or 60% compared to the same period in 2008. NGL sales volumes for the year increased 12% and natural gas volumes decreased 15% compared to the same period of 2008. The increase in NGL volumes is primarily due to increased industrial demand experienced during 2009 and the decrease in natural gas volumes is primarily due to the Waskom plant shutdown in second quarter 2009 and operational issues on various producer's gathering lines in fourth quarter 2009.

Our natural gas services segment utilizes derivative instruments to manage the risk of fluctuations in market prices for its anticipated sales of natural gas, condensate and NGLs. This activity is referred to as price risk management. For the year ended December 31, 2009, 54% of our total natural gas volumes and 35% of our total NGL volumes were hedged as compared to 58% and 33%, respectively in 2008. The impact of price risk management and marketing activities increased total natural gas and NGL revenues $0.8 million for 2009 compared to an increase of $1.0 million in the same period of 2008.

Costs of product sold. Our cost of products decreased $275.0 million, or 42%, for the year ended December 31, 2009 compared to the same period in 2008. Of the decrease, $235.5 million relates to NGLs and $39.5 million relates to natural gas. The percentage decrease in NGL cost of products sold is greater than our percentage decrease in NGL revenues as our NGL per barrel margins increased $0.17, or 9%. The percentage decrease relating to natural gas cost of products sold is greater than the percentage decrease in natural gas revenues which caused our Mmbtu margins to increase by 121%. This is primarily a result of revisions to the terms of certain producer contracts.

Operating expenses. Operating expenses remained consistent for the years ended December 31, 2009 and 2008.

Selling, general and administrative expenses. Selling, general and administrative expenses increased $2.0 million, or 39%, for the year ended December 31, 2009 compared to the same period of 2008. This increase was primarily a result of increased salary expenses due to increased headcount and compensation increases of $1.6 million and an increase in expense related to uncollectible accounts receivable of $0.4 million.

Depreciation and amortization. Depreciation and amortization increased $0.5 million, or 11%, for the year ended December 31, 2009 compared to the same period of 2008. This increase was primarily a result of normal capital expenditure activity during the current year.

In summary, our natural gas services operating income increased $2.1 million, or 76%, for the year ended December 31, 2009 compared to the year ended December 31, 2008.

Equity in earnings of unconsolidated entities. Equity in earnings of unconsolidated entities was $7.0 million and $13.2 million for the year ended December 31, 2009 and 2008, respectively, a decrease of 47%. This decrease is a result of several factors including significantly lower commodity prices and the Waskom plant shutdown during the second quarter of 2009 which contributed to our inlet volumes decreasing 5% and our fractionation volumes decreasing 5% for the year ended December 31, 2009 compared to the same period of 2008.

Table of Contents

Sulfur Services Segment

The following table summarizes our results of operations in our sulfur services segment.

	Years Ended December 31, 2009	2008
	(In thousands)	
Revenues	$ 79,631	$ 372,987
Cost of products sold	43,748	314,001
Operating expenses	17,113	17,963
Selling, general and administrative expenses	3,449	3,382
Depreciation and amortization	6,151	5,751
	9,170	31,890
Other operating income	405	66
Operating income	$ 9,575	$ 31,956
Sulfur (long tons)	1,107.4	1,094.3
Fertilizer (long tons)	238.0	227.6
Sulfur Services Volumes (long tons)	1,345.4	1,321.9

Revenues. Our sulfur services revenues decreased $293.4 million, or 79%, for the year ended December 31, 2009 compared to the year ended December 31, 2008. This decrease was a result of lower market prices in 2009 compared to 2008 while volumes remained relatively constant.

Cost of products sold. Our cost of products sold decreased $270.3 million, or 86%, for the year ended December 31, 2009 compared to the year ended December 31, 2008. This decrease was directly related to the decreased price of our raw materials in 2009 compared to 2008. Our overall gross margin per ton decreased from $44.62 in 2008 to $26.66 in 2009. This is related to commodity prices being extremely high in 2008 compared to a more normalized year like 2009.

Operating expenses. Our operating expenses decreased $0.9 million, or 5%, for the year ended December 31, 2009 compared to the year ended December 31, 2008. This decrease was a result of decreased costs relating to fuel prices for marine transportation of our sulfur products.

Selling, general, and administrative expenses. Our selling, general, and administrative expenses increased less than $0.1 million, or 2%, for the year ended December 31, 2009 compared to the year ended December 31, 2008.

Depreciation and amortization. Depreciation and amortization increased $0.4 million, or 7%, for the year ended December 31, 2009 compared to the year ended December 31, 2008. This is attributable to a new sulfur priller at our Neches facility that came online in the first quarter of 2009.

In summary, our sulfur services operating income decreased $22.4 million, or 70%, for the year ended December 31, 2009 compared to the year ended December 31, 2008.

Marine Transportation Segment

The following table summarizes our results of operations in our marine transportation segment.

Years Ended December 31,

	2009	2008
	(In thousands)	
Revenues	$ 72,103	$ 80,059
Operating expenses	52,335	57,346
Selling, general and administrative expenses	962	2,635
Depreciation and amortization	13,111	12,128
	5,695	7,950
Other operating income	116	154
Operating income	$ 5,811	$ 8,104

Revenues. Our marine transportation revenues decreased $8.0 million, or 10%, for the year ended December 31, 2009 compared to the year ended December 31, 2008. Our inland marine revenues declined $6.9 million primarily due to decreases in ancillary charges of $4.8 million and a $2.1 million decrease due to reduced charter contract rates. Our offshore revenue decreased $1.1 million primarily from reduction in offshore fleet utilization.

Operating expenses. Operating expenses decreased $5.0 million, or 9%, for the year ended December 31, 2009 compared to the year ended December 31, 2008. This was primarily a result of a decrease in fuel costs of $5.3 million and outside charter expenses of $2.1 million. These decreases were offset by increases in repair and maintenance of $1.0 million, wage and burden cost of $0.8 million and other operating expenses, including insurance premiums, of $0.6 million.

Selling, general and administrative expenses. Selling, general & administrative expenses decreased $1.7 million, or 63% for the year ended December 31, 2009 compared to the year ended December 31, 2008. This decrease was primarily a result of a reduction of bad debt expense in 2009.

Depreciation and amortization. Depreciation and amortization increased $1.0 million, or 8%, for the year ended December 31, 2009 compared to the year ended December 31, 2008. This increase was the result of capital expenditures made in the last 12 months.
Other operating income. Other operating income remained relatively flat for the year ended December 31, 2009 compared to the year ended December 31, 2008. In 2009, there were fewer gains recorded on the sale of property and equipment than in 2008.

In summary, our marine transportation operating income decreased $2.3 million, or 28%, for the year ended December 31, 2009 compared to the year ended December 31, 2008.

Equity in Earnings of Unconsolidated Entities

For the years ended December 31, 2009 and 2008, equity in earnings of unconsolidated entities relates to our unconsolidated interests in Waskom Gas Processing Company ("Waskom"), Matagorda, PIPE and BCP. With respect to BCP, the lease contract terminated in June 2009, and, as such, the investment was fully amortized as of June 20, 2009.

Equity in earnings of unconsolidated entities was $7.0 million for the year ended December 31, 2009, compared to $13.2 million for the year ended December 31, 2008, a decrease of $6.2 million. This decrease is a result of several factors including significantly lower commodity prices and the Waskom plant shutdown during the second quarter of 2009 which contributed to our inlet volumes decreasing 5% and our fractionation volumes decreasing 5% for the year ended December 31, 2009 compared to the same period of 2008.

Interest Expense

Our interest expense for all operations was $19.0 million for 2009 compared to $21.4 million for 2008, a decrease of $2.4 million, or 11%. This decrease was primarily due to a decrease in average debt outstanding and a decrease in interest rates throughout 2009 compared to 2008. Also, we had interest swap cash settlements of $7.9 million which increased interest expense in 2009.

Indirect Selling, General and Administrative Expenses

Indirect selling, general and administrative expenses were $6.1 million for 2009 compared to $5.5 million for 2008, an increase of $0.6 million or 11%.

Martin Resource Management allocated to us a portion of its indirect selling, general and administrative expenses for services such as accounting, treasury, clerical billing, information technology, administration of insurance, engineering, general office expense and employee benefit plans and other general corporate overhead functions we share with Martin Resource Management retained businesses. This allocation is based on the percentage of time spent by Martin Resource Management personnel that provide such centralized services. Generally accepted accounting principles also permit other methods for allocation of these expenses, such as basing the allocation on the percentage of revenues contributed by a segment. The allocation of these expenses between Martin Resource Management and us is subject to a number of judgments and estimates, regardless of the method used. We can provide no assurances that our method of allocation, in the past or in the future, is or will be the most accurate or appropriate method of allocation these expenses. Other methods could result in a higher allocation of selling, general and administrative expense to us, which would reduce our net income.

Table of Contents

In addition to the direct expenses, under the omnibus agreement, we are required to reimburse Martin Resource Management for indirect general and administrative and corporate overhead expenses. For the years ended December 31, 2009 and 2008, the Conflicts Committee of our general partner approved reimbursement amounts of $3.5 and $2.9 million, respectively, reflecting our allocable share of such expenses. The Conflicts Committee will review and approve future adjustments in the reimbursement amount for indirect expenses, if any, annually.

Liquidity and Capital Resources

General

Our primary sources of liquidity to meet operating expenses, pay distributions to our unitholders and fund capital expenditures are cash flows generated by our operations and access to debt and equity markets, both public and private. During the year ended December 31, 2010, we completed several transactions that have improved our liquidity position. We received net proceeds of $197.2 million from a private placement of senior notes and $50.5 million from a public offering of common units. We received net proceeds of $28.1 million from a public offering of common units which did not improve our liquidity position as we redeemed common units owned by Martin Resource Management. Additionally, we made certain strategic amendments to our credit facility.

As a result of these financing activities, discussed in further detail below, management believes that expenditures for our current capital projects will be funded with cash flows from operations, current cash balances, and our current borrowing capacity under the expanded revolving credit facility. However, it may be necessary to raise additional funds to finance our future capital requirements.

Our ability to satisfy our working capital requirements, to fund planned capital expenditures and to satisfy our debt service obligations will also depend upon our future operating performance, which is subject to certain risks. Please read “Item 1A. Risk Factors – Risks related to Our Business” for a discussion of such risks.

Debt Financing Activities

Effective March 26, 2010, our credit facility was amended to (i) decrease the size of our aggregate facility from $350.0 million to $275.0 million, (ii) convert all term loans to revolving loans, (iii) extend the maturity date from November 9, 2012 to March 15, 2013, (iv) permit us to invest up to $40.0 million in our joint ventures, (v) eliminate the covenant that limits our ability to make capital expenditures, (vi) decrease the applicable interest rate margin on committed revolver loans, (vii) limit our ability to make future acquisitions and (viii) adjust the financial covenants. For a more detailed discussion regarding our credit facility, see “Description of Our Long-Term Debt—Credit Facility” within this Item.

On March 26, 2010, we completed a private placement of $200.0 million in aggregate principal amount of 8.875% senior unsecured notes due 2018 (“2018 Notes”) to qualified institutional buyers under Rule 144A. We received proceeds of approximately $197.2 million, after deducting initial purchasers’ discounts and the expenses of the private placement. The proceeds were primarily used to repay borrowings under the Partnership’s revolving credit facility. Pursuant to the terms of a registration rights agreement entered into in connection with the offering of the 2018 Notes, we filed an exchange offer registration statement with the SEC on September 16, 2010 with respect to an offer to exchange the 2018 Notes for registered notes with substantially identical terms. The registration statement was declared effective by the SEC and the exchange offer was completed in the fourth quarter of 2010.

For a more detailed discussion regarding our credit facility, see “Description of Our Long-Term Debt—Senior Notes” within this Item.

Equity Offerings

On February 9, 2011, we completed a public offering of 1,874,500 common units, resulting in net proceeds of $70.7 million after payment of underwriters’ discounts, commissions and offering expenses. Our general partner contributed $1.5 million in cash to us in conjunction with the issuance of these units in order to maintain its 2% general partner interest in us. The net proceeds were used to pay down revolving debt under our credit facility.

Table of Contents

On August 17, 2010, we completed a public offering of 1.0 million common units, representing limited partner interests in us at a purchase price of $29.13 per common unit. We received net proceeds of approximately $28.1 million after payment of underwriters' discounts. We used the net proceeds of $28.1 million to redeem from subsidiaries of Martin Resource Management an aggregate number of common units equal to the number of common units issued in the offering. Martin Resource Management reimbursed us for our payments of commissions and offering expenses. As a result of these transactions, our general partner was not required to contribute cash to us in conjunction with the issuance of these units in order to maintain its 2% general partner interest in us since there was no net increase in the outstanding limited partner units.

On February 8, 2010, we completed a public offering of approximately 1.65 million common units, representing limited partner interests in us at a purchase price of $32.35 per common unit. We received net proceeds of approximately $50.5 million after payment of underwriters' discounts, commissions and offering expenses. Our general partner contributed $1.1 million in cash to us in conjunction with the issuance in order to maintain its 2% general partner interest in us.

Due to the foregoing, we believe that cash generated from operations and our borrowing capacity under our credit facility will be sufficient to meet our working capital requirements, anticipated maintenance capital expenditures and scheduled debt payments in 2010.

Due to restrictions on liquidity within the capital markets and the existing litigation at Martin Resource Management our ability to access the capital markets in the future may be constrained. Our near-term focus is to ensure we have sufficient liquidity to fund our growth programs, while continuing the present distribution rate to our unitholders. The uncertain economic environment and the existing litigation at Martin Resource Management has created a challenging operating environment for us to maintain our liquidity and operating cash flows at levels consistent with the recent past while maintaining the present distribution rate to our unitholders. We continue to evaluate our liquidity and capital resources and we have and will continue to consider sales of non-essential assets and other available options for additional liquidity. For example, in the second quarter of 2009 we sold the assets comprising the Mont Belvieu railcar unloading facility to Enterprise Products Operating LLC. See Note 16 to our Financial Statements — Gain on Disposal of Assets.

Within the constraints noted above, we intend to move forward with our commercially supported internal growth projects. We may revise the timing and scope of other projects as necessary to adapt to existing economic, capital market and litigation conditions affecting us.

Finally, our ability to satisfy our working capital requirements, to fund planned capital expenditures and to satisfy our debt service obligations will depend upon our future operating performance, which is subject to certain risks. For example, the impact of the uncertain economic environment may significantly affect our customers, including their ability to satisfy receivables to us on a timely basis. Please read "Item 1A. Risk Factors – Risks Related to Our Business" for a discussion of such risks.

Cash Flows and Capital Expenditures

In 2010, cash increased $5.4 million as a result of $37.5 million provided by operating activities, $81.3 million used in investing activities and $49.2 million provided by financing activities. In 2009, cash decreased $2.0 million as a result of $47.6 million provided by operating activities, $14.7 million used in investing activities and $34.9 million used in financing activities. In 2008, cash increased $3.9 million as a result of $86.3 million provided by operating activities, $106.6 million used in investing activities and $24.2 million provided by financing activities.

For 2010, our investing activities of $81.3 million consisted primarily of capital expenditures, acquisitions, proceeds from sale of property, insurance proceeds from involuntary conversion of property, plant and equipment, and investments in and returns of investments from unconsolidated partnerships. Our investment in unconsolidated partnerships helped to fund $1.2 million and $3.2 million in expansion capital expenditures made by these unconsolidated entities for the fourth quarter and year ended December 31, 2010, respectively. For 2009, our investing activities of $14.7 million consisted primarily of capital expenditures, acquisitions, proceeds from sale of property, insurance proceeds from involuntary conversion of property, plant and equipment, and investments in and returns of investments from unconsolidated partnerships. Our investment in unconsolidated partnerships helped to fund $0.4 million and $3.8 million in expansion capital expenditures made by these unconsolidated entities for the fourth quarter and year ended December 31, 2009, respectively. For 2008, our investing activities of $106.6 million consisted primarily of capital expenditures, acquisitions, proceeds from sale of property, insurance proceeds from involuntary conversion of property, plant and equipment, and investments in and returns of investments from unconsolidated partnerships. Our investment in unconsolidated partnerships helped to fund $0.9 million and $5.2 million in expansion capital expenditures made by these unconsolidated entities for the fourth quarter and year ended December 31, 2008, respectively.

For 2010, 2009 and 2008 our capital expenditures for property and equipment were $17.0 million, $44.1 million, and $107.4 million, respectively.

As to each period:

- In 2010, we spent $12.3 million for expansion and $4.7 million for maintenance (including $1.2 million for maintenance in the fourth quarter of 2010). Our expansion capital expenditures were made in connection with marine vessel conversions, construction projects associated with our terminalling and sulfur services businesses. Our maintenance capital expenditures were primarily made in our terminalling and sulfur services divisions for routine operating equipment improvements.

- In 2009, we spent $36.5 million for expansion and $7.6 million for maintenance (including $0.9 million for maintenance in the fourth quarter of 2009). Our expansion capital expenditures were made in connection with marine vessel purchases and conversions, construction projects associated with our terminalling and sulfur services businesses. Our maintenance capital expenditures were primarily made in our marine transportation segment for routine dry dockings of our vessels pursuant to the United States Coast Guard requirements.

- In 2008, we spent $89.4 million for expansion and $18.0 million for maintenance (including $7.0 million for maintenance in the fourth quarter of 2008). Our expansion capital expenditures were made in connection with marine vessel purchases and conversions, construction projects associated with our terminalling business. Our maintenance capital expenditures were primarily made in our marine transportation segment for routine dry dockings of our vessels pursuant to the United States Coast Guard requirements and in our terminalling and sulfur services at our Neches facility, where $1.5 million in maintenance capital expenditures was spent in connection with restoration of assets destroyed in Hurricanes Gustav and Ike.

In 2010, our financing activities consisted of payments of long-term debt under our credit facilities and senior notes of $442.0 million and borrowings of long-term debt under our credit facilities of $503.9 million, cash distributions paid to common and subordinated unitholders of $56.7 million, purchase of treasury units of $0.1 million and payments of debt issuance costs of $7.5 million. Additional financing activities consisted of contributions of $1.1 million from our general partner to maintain its 2% general partner interest, net proceeds from follow on public offering of $78.6 million and redemption of common units of $28.1 million.

In 2009, our financing activities consisted of payments of long-term debt under our credit facilities of $432.0 million and borrowings of long-term debt under our credit facilities of $433.7 million, cash distributions paid to common and subordinated unitholders of $47.5 million, purchase of treasury units of $0.1 million and payments of debt issuance costs of $10.4 million. Additional financing activities consisted of $20.0 million in connection with a private equity offering issuance of 714,285 common units to Martin Resource Management and contributions of $1.3 million from our general partner to maintain its 2% general partner interest.

In November 2009, we acquired the Cross assets for total consideration of $44.9 million as a result of a non-cash financing activity. As consideration for the contribution of the Cross assets, we issued 804,721 of our common units and 889,444 subordinated units to Martin Resource Management at a price of $27.96 and $25.16 per limited partner unit, respectively. In connection with the contribution of the Cross assets, our general partner made a capital contribution of $0.9 million to us in order to maintain its 2% general partner interest.

In 2008, our financing activities consisted of payments of long-term debt under our credit facilities of $257.2 million and borrowings of long-term debt under our credit facilities of $327.2 million, cash distributions paid to common and subordinated unitholders of $45.7 million, purchase of treasury units of $0.1 million and payments of debt issuance costs of $18 thousand.

Capital Resources

Historically, we have generally satisfied our working capital requirements and funded our capital expenditures with cash generated from operations and borrowings. We expect our primary sources of funds for short-term liquidity will be cash flows from operations and borrowings under our credit facility.

As of December 31, 2010, we had $374.0 million of outstanding indebtedness, consisting of outstanding borrowings of $197.5 million (net of unamortized discount) under our Senior Notes, $163.0 million under our revolving credit facility, $7.3 million under a note payable to a bank, and $6.2 million under capital lease obligations. As of December 31, 2010, we had $111.9 million of available borrowing capacity under our revolving credit facility.

Total Contractual Cash Obligations. A summary of our total contractual cash obligations as of December 31, 2010 is as follows (dollars in thousands):

Table of Contents

Type of Obligation	Total Obligation	Payment due by period Less than One Year	1-3 Years	3-5 Years	Due Thereafter
Long-Term Debt					
Revolving credit facility	$163,000	$—	$163,000	$—	$—
Senior unsecured notes	197,457	—	—	—	197,457
Note payable	7,354	993	2,219	2,576	1,566
Capital leases including current maturities	6,172	130	384	601	5,057
Non-competition agreements	200	50	100	50	—
Throughput commitment	64,025	—	8,865	12,347	42,813
Purchase obligations	7,760	7,760	—	—	—
Operating leases	47,179	9,690	18,983	9,977	8,529
Interest expense(1)					
Revolving credit facility	15,787	7,167	8,620	—	—
Senior unsecured notes	128,688	17,750	35,500	35,500	39,938
Note payable	1,830	519	800	442	69
Capital leases	5,079	972	1,868	1,715	524
Total contractual cash obligations	$644,531	$45,031	$240,339	$63,208	$295,953

(1) Interest commitments are estimated using our current interest rates for the respective credit agreements over their remaining terms.

Letter of Credit. At December 31, 2010, we had outstanding irrevocable letters of credit in the amount of $0.1 million, which were issued under our revolving credit facility.

Off Balance Sheet Arrangements. We do not have any off-balance sheet financing arrangements.

Description of Our Long-Term Debt

Senior Notes

In March 2010, we and Martin Midstream Finance Corp. (“FinCo”), a subsidiary of us (collectively, the “Issuers”), entered into (i) a Purchase Agreement, dated as of March 23, 2010 (the “Purchase Agreement”), by and among the Issuers, certain subsidiary guarantors (the “Guarantors”) and Wells Fargo Securities, LLC, RBC Capital Markets Corporation and UBS Securities LLC, as representatives of a group of initial purchasers (collectively, the “Initial Purchasers”), (ii) an Indenture, dated as of March 26, 2010 (the “Indenture”), among the Issuers, the Guarantors and Wells Fargo Bank, National Association, as trustee (the “Trustee”) and (iii) a Registration Rights Agreement, dated as of March 26, 2010 (the “Registration Rights Agreement”), among the Issuers, the Guarantors and the Initial Purchasers, in connection with a private placement to eligible purchasers of $200 million in aggregate principal amount of the Issuers’ 8.875% senior unsecured notes due 2018 (the “Notes”). We completed the aforementioned Notes offering on March 26, 2010 and received proceeds of approximately $197.2 million, after deducting initial purchaser discounts and the expenses of the private placement. The proceeds were primarily used to repay borrowings under our revolving credit facility.

In March 2010, we completed a private placement of $200.0 million in aggregate principal amount of the 2018 Notes to qualified institutional buyers under Rule 144A. We received proceeds of approximately $197.2 million, after deducting initial purchasers’ discounts and the expenses of the private placement. The proceeds were primarily used to repay borrowings under the Partnership's revolving credit facility. Pursuant to the terms of a registration rights agreement entered into in connection with the offering of the 2018 Notes, we filed an exchange offer registration statement with the SEC on September 16, 2010 with respect to an offer to exchange the 2018 Notes for registered notes with substantially identical terms. The registration statement was declared effective by the SEC and the exchange offer was completed in the fourth quarter of 2010.

Purchase Agreement.

Under the Purchase Agreement, the Issuers agreed to sell the Notes. The Notes were not registered under the Securities Act of 1933, as amended (the "Securities Act"), or any state securities laws, and unless so registered, the Notes may not be offered or sold in the United States except pursuant to an exemption from, or in a transaction not subject to, the registration requirements of the Securities Act and applicable state securities laws. The Issuers offered and issued the Notes only to qualified institutional buyers pursuant to Rule 144A under the Securities Act and to persons outside the United States pursuant to Regulation S.

Table of Contents

The Purchase Agreement contained customary representations and warranties of the parties and indemnification and contribution provisions under which the Issuers and the Guarantors, on one hand, and the Initial Purchasers, on the other, agreed to indemnify each other against certain liabilities, including liabilities under the Securities Act. The Issuers also agreed not to issue certain debt securities for a period of 60 days after March 23, 2010 without the prior written consent of Wells Fargo Securities.

Indenture.

Interest and Maturity. On March 26, 2010, the Issuers issued the Notes pursuant to the Indenture in a transaction exempt from registration requirements under the Securities Act. The Notes were resold to qualified institutional buyers pursuant to Rule 144A under the Securities Act and to persons outside the United States pursuant to Regulation S under the Securities Act. The Notes will mature on April 1, 2018. The interest payment dates are April 1 and October 1, beginning on October 1, 2010.

Optional Redemption. Prior to April 1, 2013, the Issuers have the option on any one or more occasions to redeem up to 35% of the aggregate principal amount of the Notes issued under the Indenture at a redemption price of 108.875% of the principal amount, plus accrued and unpaid interest, if any, to the redemption date of the Notes with the proceeds of certain equity offerings. Prior to April 1, 2014, the Issuers may on any one or more occasions redeem all or a part of the Notes at the redemption price equal to the sum of (i) the principal amount thereof, plus (ii) a make whole premium at the redemption date, plus accrued and unpaid interest, if any, to the redemption date. On or after April 1, 2014, the Issuers may on any one or more occasions redeem all or a part of the Notes at redemption prices (expressed as percentages of principal amount) equal to 104.438% for the twelve-month period beginning on April 1, 2014, 102.219% for the twelve-month period beginning on April 1, 2015 and 100.00% for the twelve-month period beginning on April 1, 2016 and at any time thereafter, plus accrued and unpaid interest, if any, to the applicable redemption date on the Notes.

Certain Covenants. The Indenture restricts our ability and the ability of certain of its subsidiaries to: (i) sell assets including equity interests in its subsidiaries; (ii) pay distributions on, redeem or repurchase its units or redeem or repurchase its subordinated debt; (iii) make investments; (iv) incur or guarantee additional indebtedness or issue preferred units; (v) create or incur certain liens; (vi) enter into agreements that restrict distributions or other payments from its restricted subsidiaries to us; (vii) consolidate, merge or transfer all or substantially all of its assets; (viii) engage in transactions with affiliates; (ix) create unrestricted subsidiaries; (x) enter into sale and leaseback transactions or (xi) engage in certain business activities. These covenants are subject to a number of important exceptions and qualifications. If the Notes achieve an investment grade rating from each of Moody’s Investors Service, Inc. and Standard & Poor’s Ratings Services and no Default (as defined in the Indenture) has occurred and is continuing, many of these covenants will terminate.

Events of Default. The Indenture provides that each of the following is an Event of Default: (i) default for 30 days in the payment when due of interest on the Notes; (ii) default in payment when due of the principal of, or premium, if any, on the Notes; (iii) our failure to comply with certain covenants relating to asset sales, repurchases of the Notes upon a change of control and mergers or consolidations; (iv) our failure, for 180 days after notice, to comply with its reporting obligations under the Securities Exchange Act of 1934; (v) our failure, for 60 days after notice, to comply with any of the other agreements in the Indenture; (vi) default under any mortgage, indenture or instrument governing any indebtedness for money borrowed or guaranteed by us or any of our restricted subsidiaries, whether such indebtedness or guarantee now exists or is created after the date of the Indenture, if such default: (a) is caused by a payment default; or (b) results in the acceleration of such indebtedness prior to its stated maturity, and, in each case, the principal amount of the indebtedness, together with the principal amount of any other such indebtedness under which there has been a payment default or acceleration of maturity, aggregates $20 million or more, subject to a cure provision; (vii) our or any of our restricted subsidiaries failure to pay final judgments aggregating in excess of $20 million, which judgments are not paid, discharged or stayed for a period of 60 days; (viii) except as permitted by the Indenture, any subsidiary guarantee is held in any judicial proceeding to be unenforceable or invalid or ceases for any reason to be in full force or effect, or any Guarantor, or any person acting on behalf of any Guarantor, denies or disaffirms its obligations under its subsidiary guarantee and (ix) certain events of bankruptcy, insolvency or reorganization described in the Indenture with respect to the Issuers or any of our restricted subsidiaries that is a significant subsidiary or any group of restricted subsidiaries that, taken together, would constitute a significant subsidiary of us. Upon a continuing Event of Default, the Trustee, by notice to the Issuers, or the holders of at least 25% in principal amount of the then outstanding Notes, by notice to the Issuers and the Trustee, may declare the Notes immediately due and payable, except that an Event of Default resulting from entry into a bankruptcy, insolvency or reorganization with respect to the Issuers, any restricted subsidiary of us that is a significant subsidiary or any group of its restricted subsidiaries that, taken together, would constitute a significant subsidiary of us, will automatically cause the Notes to become due and payable.

Table of Contents

Credit Facility

On November 10, 2005, we entered into a $225.0 million multi-bank credit facility comprised of a $130.0 million term loan facility and a $95.0 million revolving credit facility, which included a $20.0 million letter of credit sub-limit. Effective September 30, 2006, we increased our revolving credit facility by $25.0 million, resulting in a committed $120.0 million revolving credit facility. Effective December 28, 2007, we increased our revolving credit facility by $75.0 million, resulting in a committed $195.0 million revolving credit facility. Effective December 21, 2009, (i) we increased our revolving credit facility by approximately $72.7 million, resulting in a committed $267.8 million revolving credit facility and (ii) decreased our term loan facility by approximately $62.1 million, resulting in a $67.9 million term loan facility. Effective January 14, 2010, we modified our revolving credit facility to (i) permit investment up to $25.0 million in joint ventures and (ii) limit our ability to make capital expenditures. Effective February 25, 2010, we increased the maximum amount of borrowings and letters of credit available under our credit facility from approximately $335.7 million to $350.0 million. Effective March 26, 2010, our credit facility was amended to (i) decrease the size of our aggregate facility from $350.0 million to $275.0 million, (ii) convert all term loans to revolving loans, (iii) extend the maturity date from November 9, 2012 to March 15, 2013, (iv) permit us to invest up to $40 million in our joint ventures, (v) eliminate the covenant that limits our ability to make capital expenditures, (vi) decrease the applicable interest rate margin on committed revolver loans, (vii) limit our ability to make future acquisitions and (viii) adjust the financial covenants.

As of December 31, 2010, we had approximately $163.0 million outstanding under the revolving credit facility and $0.1 million of letters of credit issued, leaving approximately $111.9 million available under our credit facility for future revolving credit borrowings and letters of credit.

The revolving credit facility is used for ongoing working capital needs and general partnership purposes, and to finance permitted investments, acquisitions and capital expenditures. During the current fiscal year, draws on our credit facility have ranged from a low of $80.0 million to a high of $324.5 million.

The credit facility is guaranteed by substantially all of our subsidiaries. Obligations under the credit facility are secured by first priority liens on substantially all of our assets and those of the guarantors, including, without limitation, inventory, accounts receivable, bank accounts, marine vessels, equipment, fixed assets and the interests in our subsidiaries and certain of our equity method investees.

We may prepay all amounts outstanding under the credit facility at any time without premium or penalty (other than customary LIBOR breakage costs), subject to certain notice requirements. The credit facility requires mandatory prepayments of amounts outstanding thereunder with the net proceeds of certain asset sales, equity issuances and debt incurrences. Prepayments as a result of asset sales and debt incurrences require a mandatory reduction of the lenders' commitments under the credit facility equal to 25% of the corresponding mandatory prepayment, but in no event will such prepayments cause the lenders' commitments under the credit facility to be less than $250.0 million. Prepayments as a result of equity issuances do not require any reduction of the lenders' commitments under the credit facility.

Indebtedness under the credit facility bears interest, at our option, at the Eurodollar Rate (the British Bankers Association LIBOR Rate) plus an applicable margin or the Base Rate (the highest of the Federal Funds Rate plus 0.50%, the 30-day Eurodollar Rate plus 1.0%, or the administrative agent's prime rate) plus an applicable margin. We pay a per annum fee on all letters of credit issued under the credit facility, and we pay a commitment fee of 0.50% per annum on the unused revolving credit availability under the credit facility. The letter of credit fee and the applicable margins for our interest rate vary quarterly based on our leverage ratio (as defined in the new credit facility, being generally computed as the ratio of total funded debt to consolidated earnings before interest, taxes, depreciation, amortization and certain other non-cash charges) and are as follows:

Leverage Ratio	Base Rate Loans	Eurodollar Rate Loans	Letter of Credit Fees
Less than 2.75 to 1.00	2.00 %	3.00 %	3.00 %
Greater than or equal to 2.75 to 1.00 and less than 3.00 to 1.00	2.25 %	3.25 %	3.25 %
Greater than or equal to 3.00 to 1.00 and less than 3.50 to 1.00	2.50 %	3.50 %	3.50 %
Greater than or equal to 3.50 to 1.00 and less than 4.00 to 1.00	3.00 %	4.00 %	4.00 %
Greater than or equal to 4.00 to 1.00	3.25 %	4.25 %	4.25 %

Table of Contents

As of December 31, 2010, based on our leverage ratio the applicable margin for existing Eurodollar Rate borrowings is 4.00%. Effective January 1, 2011, based on our leverage ratio as of September 30, 2010, the applicable margin for Eurodollar Rate borrowings will remain at 4.00% until the next quarterly determination of our leverage ratio. The credit facility does not have a floor for the Base Rate or the Eurodollar Rate.

The credit facility includes financial covenants that are tested on a quarterly basis, based on the rolling four-quarter period that ends on the last day of each fiscal quarter. Prior to our or any of our subsidiaries' issuance of $100.0 million or more of unsecured indebtedness, the maximum permitted leverage ratio is 4.00 to 1.00. After our or any of our subsidiaries' issuance of $100.0 million or more of unsecured indebtedness, the maximum permitted leverage ratio is 4.50 to 1.00. After our or any of our subsidiaries' issuance of $100.0 million or more of unsecured indebtedness, the maximum permitted senior leverage ratio (as defined in the new credit facility, but generally computed as the ratio of total secured funded debt to consolidated earnings before interest, taxes, depreciation, amortization and certain other non-cash charges) is 2.75 to 1.00. The minimum consolidated interest coverage ratio (as defined in the new credit facility, but generally computed as the ratio of consolidated earnings before interest, taxes, depreciation, amortization and certain other non-cash charges to consolidated interest charges) is 3.00 to 1.00.

In addition, the credit facility contains various covenants that, among other restrictions, limit our and our subsidiaries' ability to:

- grant or assume liens;
- make investments (including investments in our joint ventures) and acquisitions;
- enter into certain types of hedging agreements;
- incur or assume indebtedness;
- sell, transfer, assign or convey assets;
- repurchase our equity, make distributions and certain other restricted payments, but the credit facility permits us to make quarterly distributions to unitholders so long as no default or event of default exists under the credit facility;
- change the nature of our business;
- engage in transactions with affiliates.
- enter into certain burdensome agreements;
- make certain amendments to the omnibus agreement and our material agreements;
- make capital expenditures; and
- permit our joint ventures to incur indebtedness or grant certain liens.

Each of the following will be an event of default under the credit facility:

- failure to pay any principal, interest, fees, expenses or other amounts when due;
- failure to meet the quarterly financial covenants;

- failure to observe any other agreement, obligation, or covenant in the credit facility or any related loan document, subject to cure periods for certain failures;
- the failure of any representation or warranty to be materially true and correct when made;
- our or any of our subsidiaries' default under other indebtedness that exceeds a threshold amount;
- bankruptcy or other insolvency events involving us or any of our subsidiaries;
- judgments against us or any of our subsidiaries, in excess of a threshold amount;
- certain ERISA events involving us or any of our subsidiaries, in excess of a threshold amount;
- a change in control (as defined in the credit facility);

Table of Contents

- the termination of any material agreement or certain other events with respect to material agreements;
- the invalidity of any of the loan documents or the failure of any of the collateral documents to create a lien on the collateral; and
- any of our joint ventures incurs debt or liens in excess of a threshold amount.

The credit facility also contains certain default provisions relating to Martin Resource Management. If Martin Resource Management no longer controls our general partner, or if Ruben Martin is not the chief executive officer of our general partner and a successor acceptable to the administrative agent and lenders providing more than 50% of the commitments under our credit facility is not appointed, the lenders under our credit facility may declare all amounts outstanding there under immediately due and payable. In addition, either a bankruptcy event with respect to Martin Resource Management or a judgment with respect to Martin Resource Management could independently result in an event of default under our credit facility if it is deemed to have a material adverse effect on us.

If an event of default relating to bankruptcy or other insolvency events occurs with respect to us or any of our subsidiaries, all indebtedness under our credit facility will immediately become due and payable. If any other event of default exists under our credit facility, the lenders may terminate their commitments to lend us money, accelerate the maturity of the indebtedness outstanding under the credit facility and exercise other rights and remedies. In addition, if any event of default exists under our credit facility, the lenders may commence foreclosure or other actions against the collateral. Any event of default and corresponding acceleration of outstanding balances under our credit facility could require us to refinance such indebtedness on unfavorable terms and would have a material adverse effect on our financial condition and results of operations as well as our ability to make distributions to unitholders.

If any default occurs under our credit facility, or if we are unable to make any of the representations and warranties in the credit facility, we will be unable to borrow funds or have letters of credit issued under our credit facility.

As of March 1, 2011, our outstanding indebtedness includes $135 million under our credit facility.

We are subject to interest rate risk on our credit facility and may enter into interest rate swaps to reduce this risk.

Effective September 2010, the Partnership entered into an interest rate swap that swapped $40,000 of fixed rate to floating rate. The floating rate cost is the applicable three-month LIBOR rate. This interest rate swap is not accounted for using hedge accounting and matures in April 2018.

Effective September 2010, the Partnership entered into an interest rate swap that swapped $60,000 of fixed rate to floating rate. The floating rate cost is the applicable three-month LIBOR rate. This interest rate swap is not accounted for using hedge accounting and matures in April 2018.

Effective October 2008, we entered into an interest rate swap that swapped $40.0 million of floating rate to fixed rate. The fixed rate cost was 2.820% plus our applicable LIBOR borrowing spread. Effective April 2009, we entered into two subsequent swaps to lower our effective fixed rate to 2.580% plus our applicable LIBOR borrowing spread. The original swap and the first subsequent swap were accounted for using mark-to-market accounting. The second subsequent swap was accounted for using hedge accounting. Each of the swaps were scheduled to mature in October 2010, but were terminated in March 2010.

Effective January 2008, we entered into an interest rate swap that swapped $25.0 million of floating rate to fixed rate. The fixed rate cost was 3.400% plus our applicable LIBOR borrowing spread. Effective April 2009, we entered into two subsequent swaps to lower our effective fixed rate to 3.050% plus our applicable LIBOR borrowing spread. The original swap and the first subsequent swap were accounted for using mark-to-market accounting. The second subsequent swap was accounted for using hedge accounting. Each of the swaps matured in January 2010.

Effective September 2007, we entered into an interest rate swap that swapped $25.0 million of floating rate to fixed rate. The fixed rate cost was 4.605% plus our applicable LIBOR borrowing spread. Effective March 2009, we entered into two subsequent swaps to lower our effective fixed rate to 4.305% plus our applicable LIBOR borrowing spread. The original swap and the first subsequent swap were accounted for using mark-to-market accounting. The second subsequent swap was accounted for using hedge accounting. Each of the swaps were scheduled to mature in September 2010, but were terminated in March 2010.

Table of Contents

Effective November 2006, we entered into an interest rate swap that swapped $30.0 million of floating rate to fixed rate. The fixed rate cost was 4.765% plus our applicable LIBOR borrowing spread. This interest rate swap, which matured in March 2010, was not accounted for using hedge accounting.

Effective March 2006, we entered into an interest rate swap that swapped $75.0 million of floating rate to fixed rate. The fixed rate cost was 5.25% plus our applicable LIBOR borrowing spread. Effective February 2009, we entered into two subsequent swaps to lower our effective fixed rate to 5.10% plus our applicable LIBOR borrowing spread. The original swap and the first subsequent swap were accounted for using mark-to-market accounting. The second subsequent swap was accounted for using hedge accounting. Each of the swaps were scheduled to mature in November 2010, but were terminated in March 2010.

Seasonality

A substantial portion of our revenues are dependent on sales prices of products, particularly NGLs and sulfur-based fertilizer products, which fluctuate in part based on winter and spring weather conditions. The demand for NGLs is strongest during the winter heating season. The demand for fertilizers is strongest during the early spring planting season. However, our terminalling and storage and marine transportation businesses and the molten sulfur business are typically not impacted by seasonal fluctuations. We expect to derive approximately half of our net income from our terminalling and storage, marine transportation, natural gas and sulfur businesses. Therefore, we do not expect that our overall net income will be impacted by seasonality factors. However, extraordinary weather events, such as hurricanes, have in the past, and could in the future, impact our terminalling and storage and marine transportation businesses. For example, Hurricanes Gustav and Ike in the third quarter of 2008 and Hurricanes Katrina and Rita in the third quarter of 2005 adversely impacted our operating expenses and adversely impacted our terminalling and storage and marine transportation business's revenues.

Impact of Inflation

Inflation in the United States has been relatively low in recent years and did not have a material impact on our results of operations in 2010, 2009 and 2008. However, inflation remains a factor in the United States economy and could increase our cost to acquire or replace property, plant and equipment as well as our labor and supply costs. We cannot assure our unitholders that we will be able to pass along increased costs to our customers.

Increasing energy prices could adversely affect our results of operations. Diesel fuel, natural gas, chemicals and other supplies are recorded in operating expenses. An increase in price of these products would increase our operating expenses which could adversely affect net income. We cannot assure our unitholders that we will be able to pass along increased operating expenses to our customers.

Environmental Matters

Our operations are subject to environmental laws and regulations adopted by various governmental authorities in the jurisdictions in which these operations are conducted. We incurred no significant environmental costs, liabilities or expenditures to mitigate or eliminate environmental contamination during 2010, 2009 or 2008.

Table of Contents

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

Market risk is the risk of loss arising from adverse changes in market rates and prices. We are exposed to market risks associated with commodity prices, counterparty credit and interest rates. For the year ended December 31, 2010, changes in the fair value of our derivative contracts were recorded both in earnings and accumulated other comprehensive income ("AOCI") since we have designated a portion of our derivative instruments as hedges as of December 31, 2010.

Commodity Price Risk

We are exposed to market risks associated with commodity prices, counterparty credit and interest rates. Under our hedging policy, we monitor and manage the commodity market risk associated with the commodity risk exposure of Prism Gas. In addition, we are focusing on utilizing counterparties for these transactions whose financial condition is appropriate for the credit risk involved in each specific transaction.

We use derivatives to manage the risk of commodity price fluctuations. These outstanding contracts expose us to credit loss in the event of nonperformance by the counterparties to the agreements. We have incurred no losses associated with counterparty nonperformance on derivative contracts.

On all transactions where we are exposed to counterparty risk, we analyze the counterparty's financial condition prior to entering into an agreement, establish a maximum credit limit threshold pursuant to our hedging policy, and monitor the appropriateness of these limits on an ongoing basis. We have agreements with five counterparties containing collateral provisions. Based on those current agreements, cash deposits are required to be posted whenever the net fair value of derivatives associated with the individual counterparty exceed a specific threshold. If this threshold is exceeded, cash is posted by us if the value of derivatives is a liability to us. As of December 31, 2010, we have no cash collateral deposits posted with counterparties.

We are exposed to the impact of market fluctuations in the prices of natural gas, NGLs and condensate as a result of gathering, processing and sales activities. Our exposure to these fluctuations is primarily in the gas processing component of our business. Gathering and processing revenues are earned under various contractual arrangements with gas producers. Gathering revenues are generated through a combination of fixed-fee and index-related arrangements. Processing revenues are generated primarily through contracts which provide for processing on percent-of-liquids and percent-of-proceeds basis.

1) Percent-of-liquids contracts: Under these contracts, we receive a fee in the form of a percentage of the NGLs recovered, and the producer bears all of the cost of natural gas shrink. Therefore, margins increase during periods of high NGL prices and decrease during periods of low NGL prices.

2) Percent-of-proceeds contracts: Under these contracts, we generally gather and process natural gas on behalf of certain producers, sell the resulting residue gas and NGLs at market prices and remit to producers an agreed upon percentage of the proceeds based on an index price. In other cases, instead of remitting cash payments to the producer, we deliver an agreed upon percentage of the residue gas and NGLs to the producer and sell the volumes kept to third parties at market prices. Under these types of contracts, revenues and gross margins increase as natural gas prices and NGL prices increase, and revenues and gross margins decrease as natural gas and NGL prices decease.

Market risk associated with gas processing margins by contract type, and gathering and transportation margins as a percent of total gross margin remained consistent for the years ended December 31, 2010 and 2009 as our contract mix and volumes associated with those contracts did not differ materially.

The aggregate effect of a hypothetical $1.00/MMbtu increase or decrease in the natural gas price index would result in an approximate annual gross margin change of $0.7 million. In addition, the aggregate effect of a hypothetical $10.00/Bbl increase or decrease in the crude oil price index would result in an approximate annual gross margin change of $0.9 million.

Prism Gas has entered into hedging transactions through 2012 to protect a portion of its commodity exposure from these contracts. These hedging arrangements are in the form of swaps for crude oil, natural gas and natural gasoline.

Table of Contents

Based on estimated volumes, as of December 31, 2010, we had hedged approximately 37% and 10% of our commodity risk by volume for 2011 and 2012, respectively. As of March 2, 2011, Prism Gas has hedged approximately 45% and 14% of its commodity risk by volume for 2011 and 2012, respectively.

We anticipate entering into additional commodity derivatives on an ongoing basis to manage our risks associated with these market fluctuations and will consider using various commodity derivatives, including forward contracts, swaps, collars, futures and options, although there is no assurance that we will be able to do so or that the terms thereof will be similar to our existing hedging arrangements.

The relevant payment indices for our various commodity contracts are as follows:

- Natural gas contracts - monthly posting for ANR Pipeline Co. - Louisiana as posted in Platts Inside FERC's Gas Market Report;
- Crude oil contracts - WTI NYMEX average for the month of the daily closing prices; and
- Natural gasoline contracts - Mt. Belvieu Non-TET average monthly postings as reported by the Oil Price Information Service (OPIS).

Derivative Contracts in Place
As of December 31, 2010

Period	Underlying	Notional Volume	Commodity Price We Receive	Commodity Price We Pay	Fair Value Asset (In Thousands)	Fair Value Liability (In Thousands)
January 2011-December 2011	Natural Gas	120,000 (MMBTU)	Index	$6.1250/Mmbtu	$ 201	$ —
January 2011-December 2011	Natural Gas	240,000 (MMBTU)	Index	$4.3225/Mmbtu	—	28
January 2011-December 2011	Crude Oil	24,000 (BBL)	Index	$91.20/bbl	—	51
January 2011-December 2011	Natural Gasoline	24,000 (BBL)	Index	$87.10/bbl	—	149
January 2011-December 2011	Natural Gasoline	12,000 (BBL)	Index	$88.85/bbl	—	54
January 2012-December 2012	Crude Oil	24,000 (BBL)	Index	$88.63/bbl	—	126
January 2012-December 2012	Natural Gasoline	12,000 (BBL)	Index	$90.20/bbl	—	44
					$ 201	$ 452

Our principal customers with respect to Prism Gas' natural gas gathering and processing are large, natural gas marketing services, oil and gas producers and industrial end-users. In addition, substantially all of our natural gas and NGL sales are made at market-based prices. Our standard gas and NGL sales contracts contain adequate assurance provisions which allows for the suspension of deliveries, cancellation of agreements or discontinuance of deliveries to the buyer unless the buyer provides security for payment in a form satisfactory to us.

Interest Rate Risk

We are exposed to changes in interest rates as a result of our credit facility, which had a weighted-average interest rate of 4.40% as of December 31, 2010. As of March 1, 2011, we had a total of $135 million of indebtedness outstanding under our credit facility, all of which was unhedged floating rate debt. Based on the amount of unhedged floating rate debt owed by us on December 31, 2010, the impact of a 1% increase in interest rates on this amount of debt would result in an increase in interest expense and a corresponding decrease in net income of approximately $1.6 million annually.

Historically, we have managed a portion of our interest rate risk on our revolving credit facility with interest rate swaps, which reduced our exposure to changes in interest rates by converting variable interest rates to fixed interest rates. During the first quarter 2010, we terminated all of our interest rate swaps on our revolving credit facility.

We are not exposed to changes in interest rates with respect to our Senior Notes as these obligations are fixed rate. The estimated fair value of the Senior Notes was approximately $216.4 million as of December 31, 2010, based on market prices of similar debt at December 31, 2010. Market risk is estimated as the potential decrease in fair value of our long-term debt resulting from a hypothetical increase of 1% in interest rates. Such an increase in interest rates would result in approximately a $10.7 million decrease in fair value of our long-term debt at December 31, 2010.

Table of Contents

We have entered into interest rate swap agreements to reduce the amount of interest we pay on our Senior Notes due in April 2018. Pursuant to the terms of these interest rate swap agreements, we pay a variable rate interest payment based on the three-month LIBOR and receive a fixed rate. The net difference to be paid or received from the counterparties under the interest rate swap agreement is settled quarterly and is recognized as an adjustment to interest expense. The risk associated with these interest rate swaps exposes us to an increase in interest rates which would result in an increase in interest expense and a corresponding decrease in net income.

At December 31, 2010, we are party to interest rate swap agreements as shown below:

Interest Rate Swaps
As of December 31, 2010

Date of Swap	Bank	Maturity	Notional Amount	Interest Rate We Pay	Interest Rate We Receive	Fair Value Asset (In Thousands)	Fair Value Liability (In Thousands)
September 2010	SunTrust	April 2018	$ 60,000	3 MO LIBOR	2.3150 %	$ 1,163	$ 2,362
September 2010	RBS	April 2018	$ 40,000	3 MO LIBOR	2.3150 %	778	1,568
						$ 1,941	$ 3,930

Table of Contents

Item 8. Financial Statements and Supplementary Data

The following financial statements of Martin Midstream Partners L.P. (Partnership):

Table of Contents

Report of Independent Registered Public Accounting Firm

The Board of Directors
Martin Midstream GP LLC:

We have audited the accompanying consolidated balance sheets of Martin Midstream Partners L.P. and subsidiaries as of December 31, 2010 and 2009, and the related consolidated statements of operations, changes in capital, comprehensive income, and cash flows for each of the years in the three-year period ended December 31, 2010. These financial statements are the responsibility of Martin Midstream's management. Our responsibility is to express an opinion on these 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, the consolidated financial statements referred to above present fairly, in all material respects, the consolidated financial position of Martin Midstream Partners L.P. and subsidiaries as of December 31, 2010 and 2009 and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2010, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Martin Midstream Partners L.P. and subsidiaries' internal control over financial reporting as of December 31, 2010, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated March 2, 2011 expressed an unqualified opinion on the effectiveness of Martin Midstream Partners L.P. and subsidiaries' internal control over financial reporting.

/s/ KPMG LLP

Shreveport, Louisiana
March 2, 2011

Table of Contents

Report of Independent Registered Public Accounting Firm

The Board of Directors
Martin Midstream GP LLC:

We have audited Martin Midstream Partners L.P. and subsidiaries' internal control over financial reporting as of December 31, 2010, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Martin Midstream's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control Over Financial Reporting in Item 9A(b). Our responsibility is to express an opinion on Martin Midstream's internal control over financial reporting based on our audit.

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

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

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, Martin Midstream Partners L.P. and subsidiaries maintained, in all respects, effective internal control over financial reporting as of December 31, 2010, based on criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Martin Midstream Partners L.P. and subsidiaries as of December 31, 2010 and 2009, and the related consolidated statements of operations, changes in capital, comprehensive income, and cash flows for each of the years in the three-year period ended December 31, 2010, and our report dated March 2, 2011 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP

Shreveport, Louisiana
March 2, 2011

Table of Contents

MARTIN MIDSTREAM PARTNERS L.P.
CONSOLIDATED BALANCE SHEETS

	December 31, 2010	December 31, 2009
	(Dollars in thousands)	
Assets		
Cash	$11,380	$5,956
Accounts and other receivables, less allowance for doubtful accounts of $2,528 and $481, respectively	95,276	77,413
Product exchange receivables	9,099	4,132
Inventories	52,616	35,510
Due from affiliates	6,437	3,051
Fair value of derivatives	2,142	1,872
Other current assets	2,784	1,340
Total current assets	179,734	129,274
Property, plant and equipment, at cost	632,456	584,036
Accumulated depreciation	(200,276)	(162,121)
Property, plant and equipment, net	432,180	421,915
Goodwill	37,268	37,268
Investment in unconsolidated entities	98,217	80,582
Debt issuance costs, net	13,497	10,780
Other assets	24,582	6,120
	$785,478	$685,939
Liabilities and Partners' Capital		
Current installments of long-term debt and capital lease obligations	$1,121	$111
Trade and other accounts payable	82,837	71,911
Product exchange payables	22,353	7,986
Due to affiliates	6,957	13,810
Income taxes payable	811	454
Fair value of derivatives	282	7,227
Other accrued liabilities	10,034	5,000
Total current liabilities	124,395	106,499
Long-term debt and capital leases, less current maturities	372,862	304,372
Deferred income taxes	8,213	8,628
Fair value of derivatives	4,100	—
Other long-term obligations	1,102	1,489
Total liabilities	510,672	420,988
Partners' capital	273,387	267,027
Accumulated other comprehensive loss	1,419	(2,076)
Total partners' capital	274,806	264,951
Commitments and contingencies		
	$785,478	$685,939

See accompanying notes to consolidated financial statements.

Table of Contents

MARTIN MIDSTREAM PARTNERS L.P.
CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31, 2010	2009	2008
	(Dollars in thousands, except per unit amounts)		
Revenues:			
Terminalling and storage *	$67,117	$69,710	$68,552
Marine transportation *	77,642	68,480	76,349
Product sales: *			
Natural gas services	554,482	408,982	679,375
Sulfur services	165,078	79,629	371,949
Terminalling and storage	47,799	35,584	50,219
	767,359	524,195	1,101,543
Total revenues	912,118	662,385	1,246,444
Costs and expenses:			
Cost of products sold: (excluding depreciation and amortization)			
Natural gas services *	527,232	382,542	657,662
Sulfur services *	122,121	43,386	313,143
Terminalling and storage	44,549	31,331	42,721
	693,902	457,259	1,013,526
Expenses:			
Operating expenses *	116,402	117,438	126,808
Selling, general and administrative *	21,118	19,775	19,062
Depreciation and amortization	40,656	39,506	34,893
Total costs and expenses	872,078	633,978	1,194,289
Other operating income	136	6,013	209
Operating income	40,176	34,420	52,364
Other income (expense):			
Equity in earnings of unconsolidated entities	9,792	7,044	13,224
Interest expense	(33,716)	(18,995)	(21,433)
Other, net	287	326	801
Total other income (expense)	(23,637)	(11,625)	(7,408)
Net income before taxes	16,539	22,795	44,956
Income tax benefit (expense)	(517)	(592)	(1,398)
Net income	$16,022	$22,203	$43,558
General partner’s interest in net income[1]	$3,869	$3,249	$3,301
Limited partners’ interest in net income[1]	$11,045	$17,179	$39,509
Net income per limited partner unit - basic and diluted	$0.63	$1.17	$2.72
Weighted average limited partner units - basic	17,525,089	14,680,807	14,529,826
Weighted average limited partner units - diluted	17,525,989	14,684,775	14,534,722

[1] General and limited partner’s interest in net income includes net income of the Cross assets since the date of the acquisition.

See accompanying notes to consolidated financial statements.

*Related Party Transactions Included Above

Revenues:			
Terminalling and storage	$46,823	$19,998	$18,362
Marine transportation	28,194	19,370	24,956
Product Sales	14,998	5,838	26,704
Costs and expenses:			
Cost of products sold: (excluding depreciation and amortization)			
Natural gas services	79,321	56,914	92,322
Sulfur services	16,061	12,583	13,282
Expenses:			
Operating expenses	49,286	37,284	37,661
Selling, general and administrative	10,918	7,162	6,284

Table of Contents

MARTIN MIDSTREAM PARTNERS L.P.
CONSOLIDATED STATEMENTS OF CHANGES IN CAPITAL
For the years ended December 31, 2010, 2009 and 2008

	Partners' Capital							
	Parent Net Investment	Common Units	Common Amount	Subordinated Units	Subordinated Amount	General Partner Amount	Accumulated Comprehensive Income Amount	Total
	(Dollars in thousands)							
Balances – December 31, 2007	$10,917	12,837,480	$244,520	1,701,346	$(6,022)	$4,112	$ (6,762)	$246,765
Net Income	748	—	34,978	—	4,531	3,301	—	43,558
Cash distributions ($2.91 per unit)	—	—	(37,357)	—	(4,951)	(3,409)	—	(45,717)
Conversion of subordinated units to common units	—	850,672	(2,754)	(850,672)	2,754	—	—	—
Unit-based compensation	—	3,000	39	—	—	—	—	39
Purchase of treasury units		(3,000)	(93)	—	—	—	—	(93)
Adjustment in fair value of derivatives	—	—	—	—	—	—	1,827	1,827
Balances – December 31, 2008	$11,665	13,688,152	$239,333	850,674	$(3,688)	$4,004	$ (4,935)	$246,379
Net Income	1,664	—	16,310	—	980	3,249	—	22,203
General partner contribution	—	—	—	—	—	1,324	—	1,324
Units issued in connection with Cross acquisition		804,721	16,523	889,444	16,434	—	—	32,957
Recognition of beneficial	—	—	(111)	—	111	—	—	—

conversion feature								
Issuance of common units	—	714,285	20,000	—	—	—	—	20,000
Cash distributions ($3.00 per unit)	—	—	(41,064)	—	(2,552)	(3,846)	—	(47,462)
Conversion of subordinated units to common units	—	850,674	(5,328)	(850,674)	5,328	—	—	—
Unit-based compensation	—	3,000	98	—	—	—	—	98
Purchase of treasury units	—	(3,000)	(78)	—	—	—	—	(78)
Contributions to parent	(13,329)	—	—	—	—	—	—	(13,329)
Adjustment in fair value of derivatives	—	—	—	—	—	—	2,859	2,859
Balances – December 31, 2009	$—	16,057,832	$245,683	889,444	$16,613	$4,731	$ (2,076)	$264,951
Net Income	—	—	12,151	—	—	3,871	—	16,022
Recognition of beneficial conversion feature	—	—	(1,108)	—	1,108	—	—	—
Follow-on public offerings	—	2,650,000	78,600	—	—	—	—	78,600
Redemption of common units	—	(1,000,000)	(28,070)	—	—	—	—	(28,070)
General partner contribution	—	—	—	—	—	1,089	—	1,089
Distributions to parent	—	—	(4,590)	—	—	—	—	(4,590)
Cash distributions ($3.00 per unit)	—	—	(51,886)	—	—	(4,810)	—	(56,696)
	—	3,500	113	—	—	—	—	113

Unit-based compensation								
Purchase of treasury units	—	(3,500)	(108)	—	—	—	—	(108)
Adjustment in fair value of derivatives	—	—	—	—	—	—	3,495	3,495
Balances – December 31, 2010	$—	17,707,832	$250,785	889,444	$17,721	$4,881	$ 1,419	$274,806

See accompanying notes to consolidated financial statements.

Table of Contents

MARTIN MIDSTREAM PARTNERS L.P.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Dollars in thousands)

	Year Ended December 31,		
	2010	2009	2008
	(Dollars in thousands)		
Net income	$16,022	$22,203	$43,558
Changes in fair values of commodity cash flow hedges	143	14	4,219
Commodity cash flow hedging (gains) losses reclassified to earnings	(617)	(2,646)	3,043
Changes in fair value of interest rate cash flow hedges	(241)	(1,854)	(5,435)
Interest rate cash flow hedging losses reclassified to earnings	4,210	7,345	—
Comprehensive income	$19,517	$25,062	$45,385

See accompanying notes to consolidated financial statements.

Table of Contents

MARTIN MIDSTREAM PARTNERS L.P.
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2010	2009	2008
	(Dollars in thousands)		
Cash flows from operating activities:			
Net income	$16,022	$22,203	$43,558
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	40,656	39,506	34,893
Amortization of deferred debt issue costs	4,814	1,689	1,120
Amortization of discount on notes payable	269	—	—
Deferred income taxes	(415)	294	2,442
Gain on disposition or sale of property, plant, and equipment	(136)	(4,996)	(131)
Gain on involuntary conversion of property, plant, and equipment	—	(1,017)	(65)
Equity in earnings of unconsolidated entities	(9,792)	(7,044)	(13,224)
Distributions from unconsolidated entities	—	650	500
Distribution in-kind from unconsolidated entities	10,545	5,826	9,725
Non-cash mark-to-market on derivatives	380	2,526	(2,327)
Other	113	98	39
Change in current assets and liabilities, excluding effects of acquisitions and dispositions:			
Accounts and other receivables	(17,863)	(10,471)	19,753
Product exchange receivables	(4,967)	2,792	3,988
Inventories	(17,106)	7,135	9,398
Due from affiliates	(3,386)	1,560	1,770
Other current assets	(1,444)	2,461	(992)
Trade and other accounts payable	10,918	(15,874)	(14,904)
Product exchange payables	14,366	(2,938)	(13,629)
Due to affiliates	(6,853)	4,133	5,966
Income taxes payable	357	569	(453)
Other accrued liabilities	5,382	871	101
Change in other non-current assets and liabilities	(4,342)	(2,381)	(1,190)
Net cash provided by operating activities	37,518	47,592	86,340
Cash flows from investing activities:			
Payments for property, plant, and equipment	(17,907)	(35,846)	(101,450)
Acquisitions, net of cash acquired	(46,352)	(327)	(5,983)
Payments for plant turnaround costs	(1,090)	—	—
Proceeds from sale of property, plant, and equipment	2,419	19,445	463
Insurance proceeds from involuntary conversion of property, plant and equipment	—	2,224	1,503
Investments in unconsolidated entities	(20,110)	—	—
Return of investments from unconsolidated entities	2,470	877	1,225
(Contributions to) unconsolidated entities for operations	(748)	(1,048)	(2,379)
Net cash used in investing activities	(81,318)	(14,675)	(106,621)
Cash flows from financing activities:			

Payments of long-term debt	(441,979)	(431,982)	(257,191)
Proceeds from long-term debt	503,856	433,700	327,170
Net proceeds from follow on public offering	78,600	—	—
General partner contribution	1,089	1,324	—
Redemption of common units	(28,070)	—	—
Contributions to parent	—	—	—
Purchase of treasury units	(108)	(78)	(93)
Proceeds from issuance of common units	—	20,000	—
Payments of debt issuance costs	(7,468)	(10,446)	(18)
Cash distributions paid	(56,696)	(47,462)	(45,717)
Net cash provided by (used in) financing activities	49,224	(34,944)	24,151
Net increase(decrease) in cash	5,424	(2,027)	3,870
Cash at beginning of period	5,956	7,983	4,113
Cash at end of period	$11,380	$5,956	$7,983
Supplemental schedule of non-cash investing and financing activities:			
Purchase of assets under capital lease obligations	$—	$7,764	$—
Issuance of common and subordinated units in connection with Cross acquisition	$—	$32,957	$—
Purchase of assets under note payable	$7,354	$—	$—

See accompanying notes to consolidated financial statements.

Table of Contents

MARTIN MIDSTREAM PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Dollars in Thousands)

(1) ORGANIZATION AND DESCRIPTION OF BUSINESS

Martin Midstream Partners L.P. (the "Partnership") is a publicly traded limited partnership with a diverse set of operations focused primarily in the United Stated Gulf Coast region. Its four primary business lines include: terminalling and storage services for petroleum products and by-products, natural gas services, sulfur and sulfur-based products processing, manufacturing, marketing and distribution and marine transportation services for petroleum products and by-products.

The petroleum products and by-products the Partnership collects, transports, stores and distributes are produced primarily by major and independent oil and gas companies who often turn to third parties, such as the Partnership, for the transportation and disposition of these products. In addition to these major and independent oil and gas companies, our primary customers include independent refiners, large chemical companies, fertilizer manufacturers and other wholesale purchasers of these products. The Partnership operates primarily in the Gulf Coast region of the United States, which is a major hub for petroleum refining, natural gas gathering and processing and support services for the oil and gas exploration and production industry.

The Partnership owns Prism Gas Systems I, L.P. ("Prism Gas") which is engaged in the gathering, processing and marketing of natural gas and natural gas liquids, predominantly in Texas and northwest Louisiana. Prism Gas owns a 50% ownership interest in Waskom Gas Processing Company ("Waskom"), the Matagorda Offshore Gathering System ("Matagorda"), and Panther Interstate Pipeline Energy LLC ("PIPE"), each accounted for under the equity method of accounting.

(2) SIGNIFICANT ACCOUNTING POLICIES

(a) Principles of Presentation and Consolidation

The consolidated financial statements include the financial statements of the Partnership and its wholly-owned subsidiaries and equity method investees. In the opinion of the management of the Partnership's general partner, all adjustments and elimination of significant intercompany balances necessary for a fair presentation of the Partnership's results of operations, financial position and cash flows for the periods shown have been made. All such adjustments are of a normal recurring nature. In addition, the Partnership evaluates its relationships with other entities to identify whether they are variable interest entities under certain provisions of the Financial Accounting Standards Board ("FASB") Accounting Standards Codification ("ASC"), 810-10 and to assess whether it is the primary beneficiary of such entities. If the determination is made that the Partnership is the primary beneficiary, then that entity is included in the consolidated financial statements in accordance with ASC 810-10. No such variable interest entities exist as of December 31, 2010 or 2009.

The Partnership acquired the assets of Cross Oil Refining & Marketing Inc. ("Cross") from Martin Resource Management ("Martin Resource Management") in November 2009 as described in Note 5. The acquisition of the Cross assets was considered a transfer of net assets between entities under common control. The acquisition of the Cross assets and increase in partners' capital for the common and subordinated units issued in November 2009 are recorded at amounts based on the historical carrying value of the Cross assets at that date, and the Partnership is required to revise its historical financial statements to include the activities of the Cross assets as of the date of common control. Martin Resource Management acquired Cross in November 2006; however, the activity for the period Cross was owned by Martin Resource Management during 2006 was not considered significant to the Partnership's consolidated financial statements and has been excluded from the consolidated financial statements. The Partnership's historical financial statements for 2008 and the period January 1, 2009 through November 24, 2009 have been revised to reflect the financial position, cash flows and results of operations attributable to the Cross assets as if the Partnership owned the Cross assets for these periods. Net income attributable to the Cross assets for periods prior to the Partnership's acquisition of the assets is not allocated to the general and limited partners for purposes of calculating net income per limited partner unit. See Note (2)(o).

(b) Product Exchanges

The Partnership enters into product exchange agreements with third parties whereby the Partnership agrees to exchange NGLs and sulfur with third parties. The Partnership records the balance of exchange products due to other companies under these agreements at quoted market product prices and the balance of exchange products due from other companies at the lower of cost or market. Cost is determined using the first-in, first-out ("FIFO") method. Revenue and costs related to product exchanges are recorded on a gross basis.

Table of Contents

MARTIN MIDSTREAM PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Dollars in Thousands)

(c) Inventories

Inventories are stated at the lower of cost or market. Cost is determined by using the first-in, first-out (FIFO) method for all inventories.

(d) Revenue Recognition

Terminalling and storage – Revenue is recognized for storage contracts based on the contracted monthly tank fixed fee. For throughput contracts, revenue is recognized based on the volume moved through the Partnership's terminals at the contracted rate. For the Partnership's tolling agreement, revenue is recognized based on the contracted monthly reservation fee and throughput volumes moved through the facility. When lubricants and drilling fluids are sold by truck, revenue is recognized upon delivering product to the customers as title to the product transfers when the customer physically receives the product.

Natural gas services – Natural gas gathering and processing revenues are recognized when title passes or service is performed. NGL distribution revenue is recognized when product is delivered by truck to our NGL customers, which occurs when the customer physically receives the product. When product is sold in storage, or by pipeline, the Partnership recognizes NGL distribution revenue when the customer receives the product from either the storage facility or pipeline.

Sulfur services – Revenues are recognized when the products are delivered, which occurs when the customer has taken title and has assumed the risks and rewards of ownership based on specific contract terms at either the shipping or delivery point.

Marine transportation – Revenue is recognized for contracted trips upon completion of the particular trip. For time charters, revenue is recognized based on a per day rate.

(e) Equity Method Investments

The Partnership uses the equity method of accounting for investments in unconsolidated entities where the ability to exercise significant influence over such entities exists. Investments in unconsolidated entities consist of capital contributions and advances plus the Partnership's share of accumulated earnings as of the entities' latest fiscal year-ends, less capital withdrawals and distributions. Investments in excess of the underlying net assets of equity method investees, specifically identifiable to property, plant and equipment, are amortized over the useful life of the related assets. Excess investment representing equity method goodwill is not amortized but is evaluated for impairment, annually. Under certain provisions of ASC 350-20, related to goodwill, this goodwill is not subject to amortization and is accounted for as a component of the investment. Equity method investments are subject to impairment under the provisions of ASC 323-10, which relates to the equity method of accounting for investments in common stock. No portion of the net income from these entities is included in the Partnership's operating income.

The Partnership's Prism Gas subsidiary owns an unconsolidated 50% interest in Waskom, Matagorda, and PIPE. As a result, these assets are accounted for by the equity method.

(f) Property, Plant, and Equipment

Owned property, plant, and equipment is stated at cost, less accumulated depreciation. Owned buildings and equipment are depreciated using straight-line method over the estimated lives of the respective assets.

Equipment under capital leases is stated at the present value of minimum lease payments less accumulated amortization. Equipment under capital leases is amortized straight line over the estimated useful life of the asset.

Routine maintenance and repairs are charged to operating expense while costs of betterments and renewals are capitalized. When an asset is retired or sold, its cost and related accumulated depreciation are removed from the accounts and the difference between net book value of the asset and proceeds from disposition is recognized as gain or loss.

Table of Contents

MARTIN MIDSTREAM PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Dollars in Thousands)

(g) Goodwill and Other Intangible Assets

Goodwill represents the excess of costs over fair value of assets of businesses acquired. Goodwill and intangible assets acquired in a purchase business combination and determined to have an indefinite useful life are not amortized, but instead tested for impairment at least annually in accordance with certain provisions of ASC 350-20. Intangible assets with estimated useful lives are amortized over their respective estimated useful lives to their estimated residual values, and reviewed for impairment under certain provisions of ASC 360-10 related to accounting for impairment or disposal of long-lived assets. Other intangible assets primarily consist of covenants not-to-compete and contracts obtained through business combinations and are being amortized over the life of the respective agreements.

Goodwill is subject to a fair-value based impairment test on an annual basis, or more often if events or circumstances indicate there may be impairment. The Partnership is required to identify its reporting units and determine the carrying value of each reporting unit by assigning the assets and liabilities, including the existing goodwill and intangible assets. Goodwill is assigned to reporting units at the date the goodwill is initially recorded. Once goodwill has been assigned to reporting units, it no longer retains its association with a particular acquisition, and all of the activities within a reporting unit, whether acquired or organically grown, are available to support value of the goodwill.

The Partnership performed the annual impairment tests as of September 30, 2010, September 30, 2009 and September 30, 2008, respectively. In performing such tests, it was determined that there were four “reporting units” which contained goodwill. These reporting units were in each of the four reporting segments: terminalling, natural gas services, marine transportation, and sulfur services. The estimated fair value of the reporting units with goodwill were developed using the guideline public company method, the guideline transaction method, and the discounted cash flow (“DCF”) method using observable market data where available. To the extent the carrying amount of a reporting unit exceeds the fair value of the reporting unit, the Partnership would be required to perform the second step of the impairment test, as this is an indication that the reporting unit goodwill may be impaired. At September 30, 2010, 2009 and 2008 the estimated fair value of each of the four reporting units was in excess of its carrying value which indicates no impairment existed.

As a result of the deterioration in the overall stock market subsequent to September 30, 2008 and the decline in the Partnership’s unit price, the Partnership reviewed specific factors, as outlined under certain provisions of ASC 350-20, to determine if the Partnership had a trigging event that required it to test the goodwill for impairment as of December 31, 2008. These factors included whether there have been any significant fundamental changes since the annual impairment test to (i) the Partnership as a whole or to the reporting units, including regulatory changes, (ii) the level of operating cash flows, (iii) the expectation of future levels of operating cash flows, (iv) the executive management team, and (v) the carrying value of the other long-lived assets. While these factors did not indicate a triggering event occurred, the Partnership’s unit price fell to a point by December 31, 2008 that resulted in the total market capitalization being less than the partner’s equity. The Partnership determined this to be a triggering event requiring the Partnership to perform an impairment test as of December 31, 2008. As a result of the goodwill impairment test for each of the four reporting units as of December 31, 2008, no impairment was determined to exist.

(h) Debt Issuance Costs

Debt issuance costs relating to the Partnership’s line of credit facility and senior notes are deferred and amortized over the terms of the debt arrangements.

In connection with the Partnership's issuance of Senior Notes during March 2010, it incurred debt issuance costs of $6,045.

In connection with the amendment and expansion of the Partnership's multi-bank credit facility in December, 2009, it incurred debt issuance costs of $10,383. In connection with the amendment and restatement of the Partnership's credit facility in March 2010, it incurred additional debt issuance costs of $1,423. Due to a reduction in the number of lenders under the Partnership's multi-bank credit agreement, $634 and $495 of the existing debt issuance costs were determined not to have continuing benefit and were expensed during 2010 and 2009, respectively. These debt issuance costs, along with the remaining unamortized deferred issuance costs relating to the line of credit facility as of November 10, 2005 which remain deferred, are amortized over the term of the revised debt arrangement.

MARTIN MIDSTREAM PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Dollars in Thousands)

Amortization of debt issuance cost, which is included in interest expense for the years ended December 31, 2010, 2009 and 2008, totaled $4,814, $1,689, and $1,120, respectively, and accumulated amortization amounted to $4,920 and $105 at December 31, 2010 and 2009, respectively.

(i) Impairment of Long-Lived Assets

In accordance with ASC 360-10, long-lived assets, such as property, plant and equipment, are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Recoverability of assets to be held and used is measured by a comparison of the carrying amount of an asset to estimated undiscounted future cash flows expected to be generated by the asset. If the carrying amount of an asset exceeds its estimated future cash flows, an impairment charge is recognized by the amount by which the carrying amount of the asset exceeds the fair value of the asset. Assets to be disposed of would be separately presented in the balance sheet and reported at the lower of the carrying amount or fair value less costs to sell, and are no longer depreciated. The assets and liabilities of a disposed group classified as held for sale would be presented separately in the appropriate asset and liability sections of the balance sheet. The Partnership has not identified any triggering events in 2010, 2009 or 2008 that would require an assessment for impairment of long-lived assets.

(j) Asset Retirement Obligation

Under ASC 410-20, which relates to accounting requirements for costs associated with legal obligations to retire tangible, long-lived assets, the Partnership records an Asset Retirement Obligation (“ARO”) at fair value in the period in which it is incurred by increasing the carrying amount of the related long-lived asset. In each subsequent period, the liability is accreted over time towards the ultimate obligation amount and the capitalized costs are depreciated over the useful life of the related asset. The Partnership’s fixed assets include land, buildings, transportation equipment, storage equipment, marine vessels and operating equipment.

The transportation equipment includes pipeline systems. The Partnership transports NGLs through the pipeline system and gathering system. The Partnership also gathers natural gas from wells owned by producers and delivers natural gas and NGLs on the Partnership’s pipeline systems, primarily in Texas and Louisiana to the fractionation facility of the Partnership’s 50% owned joint venture. The Partnership is obligated by contractual or regulatory requirements to remove certain facilities or perform other remediation upon retirement of the Partnership’s assets. However, the Partnership is not able to reasonably determine the fair value of the asset retirement obligations for the Partnership’s trunk and gathering pipelines and the Partnership’s surface facilities, since future dismantlement and removal dates are indeterminate. In order to determine a removal date of the Partnership’s gathering lines and related surface assets, reserve information regarding the production life of the specific field is required. As a transporter and gatherer of natural gas, the Partnership is not a producer of the field reserves, and the Partnership therefore does not have access to adequate forecasts that predict the timing of expected production for existing reserves on those fields in which the Partnership gathers natural gas. In the absence of such information, the Partnership is not able to make a reasonable estimate of when future dismantlement and removal dates of the Partnership’s gathering assets will occur. With regard to the Partnership’s trunk pipelines and their related surface assets, it is impossible to predict when demand for transportation of the related products will cease. The Partnership’s right-of-way agreements allow us to maintain the right-of-way rather than remove the pipe. In addition, the Partnership can evaluate the Partnership’s trunk pipelines for alternative uses, which can be and have been found. The Partnership will record such asset retirement obligations in the period in which more information becomes available for us to reasonably estimate the settlement dates of the retirement obligations.

(k) Derivative Instruments and Hedging Activities

In accordance with certain provisions of ASC 815-10 related to accounting for derivative instruments and hedging activities, all derivatives and hedging instruments are included on the balance sheet as an asset or liability measured at fair value and changes in fair value are recognized currently in earnings unless specific hedge accounting criteria are met. If a derivative qualifies for hedge accounting, changes in the fair value can be offset against the change in the fair value of the hedged item through earnings or recognized in other comprehensive income until such time as the hedged item is recognized in earnings.

Table of Contents

Derivative instruments not designated as hedges are being marked to market with all market value adjustments being recorded in the consolidated statements of operations. As of December 31, 2010, the Partnership has designated a portion of its derivative instruments as qualifying cash flow hedges. Fair value changes for these hedges have been recorded in accumulated other comprehensive income as a component of equity.

(l) Comprehensive Income

Comprehensive income includes net income and other comprehensive income. Other comprehensive income for the Partnership includes unrealized gains and losses on derivative financial instruments. In accordance ASC 815-10, the Partnership records deferred hedge gains and losses on its derivative financial instruments that qualify as cash flow hedges as other comprehensive income.

(m) Unit Grants

In August 2010, the Partnership issued 1,500 restricted common units to each of two new non -employee directors under its long-term incentive plan from 500 treasury units purchased by the Partnership in the open market for $16 and 2,500 common units from forfeited unit grants. These units vest in 25% increments beginning in January 2011 and will be fully vested in January 2014.

In May 2010, the Partnership issued 1,000 restricted common units to each of its non-employee directors under its long-term incentive plan from treasury units purchased by the Partnership in the open market for $92. These units vest in 25% increments beginning in January 2011 and will be fully vested in January 2014.

In August 2009, the Partnership issued 1,000 restricted common units to each of its non-employee directors under its long-term incentive plan from treasury units purchased by the Partnership in the open market for $77. These units vest in 25% increments beginning in January 2010 and will be fully vested in January 2013.

In May 2008, the Partnership issued 1,000 restricted common units to each of its non-employee directors under its long-term incentive plan from treasury units purchased by the Partnership in the open market for $93. These units vest in 25% increments beginning in January 2009 and will be fully vested in January 2012.

The Partnership accounts for the transaction under certain provisions of FASB ASC 505-50-55 related to equity-based payments to non-employees. The cost resulting from the unit-based payment transactions was $113, $98, and $39 for the years ended December 31, 2010, 2009 and 2008, respectively.

(n) Incentive Distribution Rights

The Partnership's general partner, Martin Midstream GP LLC, holds a 2% general partner interest and certain incentive distribution rights in the Partnership. Incentive distribution rights represent the right to receive an increasing percentage of cash distributions after the minimum quarterly distribution, any cumulative arrearages on common units, and certain target distribution levels have been achieved. The Partnership is required to distribute all of its available cash from operating surplus, as defined in the partnership agreement. The target distribution levels entitle the general partner to receive 15% of quarterly cash distributions in excess of $0.55 per unit until all unit holders have received $0.625 per unit, 25% of quarterly cash distributions in excess of $0.625 per unit until all unit holders have received $0.75 per unit, and 50% of quarterly cash distributions in excess of $0.75 per unit. For the years ended

December 31, 2010, 2009 and 2008, the general partner received $3,623, $2,896, and $2,495 in incentive distributions.

(o) Net Income per Unit

In March 2008, the FASB amended the provisions of ASC 260-10 related to earnings per share, which addresses the application of the two-class method in determining income per unit for master limited partnerships having multiple classes of securities that may participate in partnership distributions accounted for as equity distributions. To the extent the partnership agreement does not explicitly limit distributions to the general partner, any earnings in excess of distributions are to be allocated to the general partner and limited partners utilizing the distribution formula for available cash specified in the partnership agreement. When current period distributions are in excess of earnings, the excess distributions for the period are to be allocated to the general partner and limited partners based on their respective sharing of losses specified in the partnership agreement. ASC 260-10 is to be applied retrospectively for all financial statements presented and is effective for financial statements issued for fiscal years beginning after December 15, 2008, and interim periods within those fiscal years.

Table of Contents

MARTIN MIDSTREAM PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Dollars in Thousands)

The Partnership adopted the amended provisions of ASC 260-10 on January 1, 2009. Adoption did not impact the Partnership's computation of earnings per limited partner unit as cash distributions exceeded earnings for the years ended December 31, 2010, 2009 and 2008, respectively, and the IDRs do not share in losses under the partnership agreement. In the event the Partnership's earnings exceed cash distributions, ASC 260-10 will have an impact on the computation of the Partnership's earnings per limited partner unit. The Partnership agreement does not explicitly limit distributions to the general partner; therefore, any earnings in excess of distributions are to be allocated to the general partner and limited partners utilizing the distribution formula for available cash specified in the Partnership agreement. For years ended December 31, 2010, 2009 and 2008, the general partner's interest in net income, including the IDRs, represents distributions declared after period end on behalf of the general partner interest and IDRs less the allocated excess of distributions over earnings for the periods.

General and limited partner interest in net income includes only net income of the Cross assets since the date of acquisition. Accordingly, net income of the Partnership is adjusted to remove the net income attributable to the Cross assets prior to the date of acquisition and such income is allocated to the Parent. The recognition of the beneficial conversion feature for the period is considered a deemed distribution to the subordinated unit holders and reduces net income available to common limited partners in computing net income per unit.

For purposes of computing diluted net income per unit, the Partnership uses the more dilutive of the two-class and if-converted methods. Under the if-converted method, the beneficial conversion feature is added back to net income available to common limited partners, the weighted-average number of subordinated units outstanding for the period is added to the weighted-average number of common units outstanding for purposes of computing basic net income per unit and the resulting amount is compared to the diluted net income per unit computed using the two-class method.

The following table reconciles net income to limited partners' interest in net income:

	Years Ended December 31,		
	2010	2009	2008
Net income attributable to Martin Midstream Partners L. P	$ 16,022	$ 22,203	$ 43,558
Less pre-acquisition income allocated to Parent	—	1,664	748
Less general partner's interest in net income:			
Distributions payable on behalf of IDRs	3,623	2,896	2,495
Distributions payable on behalf of general partner interest	1,187	949	914
Distributions payable to the general partner interest in excess of earnings allocable to the general partner interest	(941)	(596)	(108)
Less beneficial conversion feature	1,108	111	—
Limited partners' interest in net income	$ 11,045	$ 17,179	$ 39,509

The weighted average units outstanding for basic net income per unit were 17,525,089, 14,680,807, and 14,529,826 for years ended December 31, 2010, 2009 and 2008, respectively. For diluted net income per unit, the weighted average units outstanding were increased by 900, 3,968, and 4,896 units for the years ended December 31, 2010, 2009 and 2008, respectively, due to the dilutive effect of restricted units granted under the Partnership's long-term incentive plan.

(p) Indirect Selling, General and Administrative Expenses

Indirect selling, general and administrative expenses are incurred by Martin Resource Management Corporation ("Martin Resource Management") and allocated to the Partnership to cover costs of centralized corporate functions such as accounting, treasury, engineering, information technology, risk management and other corporate services. Such expenses are based on the percentage of time spent by Martin Resource Management's personnel that provide such centralized services. Under the omnibus agreement, we are required to reimburse Martin Resource Management for indirect general and administrative and corporate overhead expenses. For the years ended December 31, 2010, 2009 and 2008, the Conflicts Committee of our general partner approved reimbursement amounts of $3,791, $3,542, and $2,896, respectively, reflecting our allocable share of such expenses. The Conflicts Committee will review and approve future adjustments in the reimbursement amount for indirect expenses, if any, annually.

Table of Contents

MARTIN MIDSTREAM PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Dollars in Thousands)

(q) Environmental Liabilities and Litigation

The Partnership's policy is to accrue for losses associated with environmental remediation obligations when such losses are probable and reasonably estimable. Accruals for estimated losses from environmental remediation obligations generally are recognized no later than completion of the remedial feasibility study. Such accruals are adjusted as further information develops or circumstances change. Costs of future expenditures for environmental remediation obligations are not discounted to their present value. Recoveries of environmental remediation costs from other parties are recorded as assets when their receipt is deemed probable.

(r) Accounts Receivable and Allowance for Doubtful Accounts.

Trade accounts receivable are recorded at the invoiced amount and do not bear interest. The allowance for doubtful accounts is the Partnership's best estimate of the amount of probable credit losses in the Partnership's existing accounts receivable.

(s) Deferred Catalyst Costs

The cost of the periodic replacement of catalysts is deferred and amortized over the catalyst's estimated useful life, which ranges from 24-36 months.

(t) Deferred Turnaround Costs

The Partnership capitalizes the cost of major turnarounds and amortizes these costs over the estimated period to the next turnaround, which ranges from 24-36 months.

(u) Use of Estimates

Management has made a number of estimates and assumptions relating to the reporting of assets and liabilities and the disclosure of contingent assets and liabilities to prepare these consolidated financial statements in conformity with accounting principles generally accepted in the United States of America. Actual results could differ from those estimates.

(v) Income Taxes

With respect to the Partnership's taxable subsidiary (Woodlawn Pipeline Co., Inc.) and the Cross assets prior to the date of acquisition, income taxes are accounted for under the asset and liability method. Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax basis. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date.

(3) FAIR VALUE MEASUREMENTS

The Partnership follows the provisions of ASC 820 related to fair value measurements and disclosures, which established a framework for measuring fair value and expanded disclosures about fair value measurements. The adoption of this guidance had no impact on the Partnership's financial position or results of operations.

ASC 820 applies to all assets and liabilities that are being measured and reported on a fair value basis. This statement enables the reader of the financial statements to assess the inputs used to develop those measurements by establishing a hierarchy for ranking the quality and reliability of the information used to determine fair values. ASC 820 establishes a three-tier fair value hierarchy, which prioritizes the inputs used in measuring fair value of each asset and liability carried at fair value into one of the following categories:

Table of Contents

MARTIN MIDSTREAM PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Dollars in Thousands)

Level 1: Quoted market prices in active markets for identical assets or liabilities.
Level 2: Observable market based inputs or unobservable inputs that are corroborated by market data.
Level 3: Unobservable inputs that are not corroborated by market data.

The Partnership's derivative instruments, which consist of commodity and interest rate swaps, are required to be measured at fair value on a recurring basis. The fair value of the Partnership's derivative instruments is determined based on inputs that are readily available in public markets or can be derived from information available in publicly quoted markets, which is considered Level 2. Refer to Note 13 for further information on the Partnership's derivative instruments and hedging activities.

The following items are measured at fair value on a recurring basis and are subject to the disclosure requirements of ASC 820 at December 31, 2010:

Description	December 31, 2010	Fair Value Measurements at Reporting Date Using Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Assets				
Interest rate derivatives	$1,941	$ —	$1,941	$ —
Natural gas derivatives	201	—	201	—
Total assets	$2,142	$—	$2,142	$ —
Liabilities				
Interest rate derivatives	$3,930	$—	$3,930	$ —
Natural gas derivatives	28	—	28	—
Crude oil derivatives	177	—	177	—
Natural gas liquids derivatives	247	—	247	—
Total liabilities	$4,382	$—	$4,382	$ —

The following items are measured at fair value on a recurring basis and are subject to the disclosure requirements of ASC 820 at December 31, 2009:

Description	December 31, 2009	Fair Value Measurements at Reporting Date Using Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)

Assets				
Interest rate derivatives	$1,286	$ —	$1,286	$ —
Natural gas derivatives	70	—	70	—
Crude oil derivatives	275	—	275	—
Natural gas liquids derivatives	241	—	241	—
Total assets	$1,872	$—	$1,872	$ —
Liabilities				
Interest rate derivatives	$6,611	$—	$6,611	$ —

Table of Contents

MARTIN MIDSTREAM PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Dollars in Thousands)

		Fair Value Measurements at Reporting Date Using		
Description	December 31, 2009	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Crude oil derivatives	290	—	290	—
Natural gas liquids derivatives	326	—	326	—
Total liabilities	$7,227	$—	$7,227	$ —

ASB ASC 825-10-65, Disclosures about Fair Value of Financial Instruments, requires that the Partnership disclose estimated fair values for its financial instruments. Fair value estimates are set forth below for the Partnership's financial instruments. The following methods and assumptions were used to estimate the fair value of each class of financial instrument:

- Accounts and other receivables, trade and other accounts payable, other accrued liabilities, income taxes payable and due from/to affiliates — The carrying amounts approximate fair value because of the short maturity of these instruments.

- Long-term debt including current installments — The carrying amount of the revolving and term loan facilities approximates fair value due to the debt having a variable interest rate. The estimated fair value of the Senior Notes was approximately $216,366 as of December 31, 2010, based on market prices of similar debt at December 31, 2010.

(4) RECENT ACCOUNTING PRONOUNCEMENTS

In December 2009, FASB amended the provisions of ASC 810 related to the consolidation of variable interest entities. It requires reporting entities to evaluate former qualifying special purpose entities for consolidation, changes the approach to determining a variable interest entity's ("VIE") primary beneficiary from a quantitative assessment to a qualitative assessment designed to identity a controlling financial interest and increases the frequency of required reassessments to determine whether a company is the primary beneficiary of a VIE. It also clarifies, but does not significantly change, the characteristics that identify a VIE. This amended guidance required additional year-end and interim disclosures for public companies that are similar to the disclosures required by ASC 810-10-50-8 through 50-19 and 860-10-50-3 through 50-9. The Partnership adopted this amended guidance on January 1, 2010. The adoption did not have an impact on the Partnership's financial position or results of operations.

(5) ACQUISITIONS

(a) Darco Gathering System

On November 1, 2010, the Partnership, through its wholly owned subsidiary, Prism Gas, acquired approximately 20 miles of natural gas gathering pipeline and various equipment located in Harrison County, Texas. The final purchase price of approximately $25,015 was funded by borrowings under the Partnership's credit agreement.

The purchase price including other intangibles reflected as other assets was allocated as follows:

Property, plant and equipment	9,925
Other assets	15,090
	$25,015

The identifiable intangible asset of $15,090 is a life of lease contract with an active producer in the Haynesville Shale and Cotton Valley sand. The contract is subject to amortization over an approximate useful life of twenty years.

Table of Contents

MARTIN MIDSTREAM PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Dollars in Thousands)

(b) Harrison Gathering System

On January 15, 2010, the Partnership, through Prism Gas Systems I, L.P. ("Prism Gas"), as 50% owner and the operator of Waskom Gas Processing Company ("Waskom"), through Waskom's wholly-owned subsidiary Waskom Midstream LLC, acquired from Crosstex North Texas Gathering, L.P., a 100% interest in approximately 62 miles of gathering pipeline, two 35 MMcfd dew point control plants and equipment referred to as the Harrison Gathering System. The Partnership's share of the acquisition cost was approximately $20,000 and was recorded as an investment in an unconsolidated entity.

(c) East Harrison Pipeline System.

In December 2009, the Partnership acquired, through Prism Gas, from Woodward Partners, Ltd. 6.45 miles of gathering pipeline referred to as the East Harrison Pipeline System for $327. The system currently transports approximately 500 Mcfd of natural gas under various transport contracts which provide for a minimum monthly fee.

(d) Cross Refining Assets.

In November 2009, the Partnership closed a transaction with Martin Resource Management Corporation ("Martin Resource Management") and Cross Refining & Marketing, Inc. ("Cross"), a wholly owned subsidiary of Martin Resource Management, in which the Partnership acquired certain specialty lubricants processing assets ("Assets") from Cross for total consideration of $44,878 (the "Contribution"). As consideration for the Contribution, the Partnership issued 804,721 common units and 889,444 subordinated units to Martin Resource Management at a price of $27.96 and $25.16 per limited partner unit, respectively. In connection with the Contribution, the General Partner made a capital contribution of $918 in cash to the Partnership in order to maintain its 2% general partner interest.

The Partnership accounted for the Cross acquisition as a transfer of net assets between entities under common control pursuant to the provisions of FASB ASC 850. The Cross assets were recorded at $32,957, which represents the amounts reflected in Martin Resource Management's historical consolidated financial statements. The difference between the purchase price and Martin Resource Management's carrying value of the combined net assets acquired and liabilities assumed was recorded as an adjustment to partners' capital.

(6) ISSUANCE OF COMMON UNITS

On August 17, 2010, the Partnership completed a public offering of 1,000,000 common units, representing limited partner interests at a purchase price of $29.13 per common unit. The Partnership received net proceeds of approximately $28,070 after payment of underwriters' discounts. The Partnership used the net proceeds of $28,070 to redeem from subsidiaries of Martin Resource Management an aggregate number of common units equal to the number of common units issued in the offering. Martin Resource Management reimbursed the Partnership for its payments of commissions and offering expenses. As a result of these simultaneous transactions, the Partnership's general partner was not required to contribute cash to the Partnership in conjunction with the issuance of these units in order to maintain its 2% general partner interest in the Partnership since there was no net increase in the outstanding limited partner units.

On February 8, 2010, the Partnership completed a public offering of 1,650,000 common units at a price of $32.35 per common unit, before the payment of underwriters' discounts, commissions and offering expenses (per unit value is in dollars, not thousands). Following this offering, the common units represented a 93.3% limited partner interest in the Partnership. Total proceeds from the sale of the 1,650,000 common units, net of underwriters' discounts, commissions and offering expenses were $50,530. The Partnership's general partner contributed $1,089 in cash to the Partnership in conjunction with the issuance in order to maintain its 2% general partner interest in the Partnership. On February 8, 2010, the Partnership reduced the outstanding balance under its revolving credit facility by $45,000.

In addition to the units referred to in Note 5(d) above, in November 2009, the Partnership closed a private equity sale with Martin Resource Management, under which Martin Resource Management invested $20,000 in cash in the Partnership in exchange for 714,285 common units of the Partnership. In connection with the issuance of these common units, the General Partner made a capital contribution to the Partnership of $408 in order to maintain its 2% general partner interest in the Partnership.

Table of Contents

MARTIN MIDSTREAM PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Dollars in Thousands)

(7) INVENTORIES

Components of inventories at December 31, 2010 and 2009 were as follows:

	2010	2009
Natural gas liquids	$ 19,775	$ 15,002
Sulfur	15,933	2,540
Sulfur Based Products	9,027	10,053
Lubricants	5,267	4,684
Other	2,614	3,231
	$ 52,616	$ 35,510

(8) PROPERTY, PLANT AND EQUIPMENT

At December 31, 2010 and 2009, property, plant, and equipment consisted of the following:

	Depreciable Lives	2010	2009
Land	—	$ 20,200	$ 15,759
Improvements to land and buildings	10-25 years	53,655	48,704
Transportation equipment	3-7 years	1,816	1,786
Storage equipment	5-20 years	62,372	59,597
Marine vessels	4-25 years	226,376	210,593
Operating equipment	3-20 years	253,271	238,956
Furniture, fixtures and other equipment	3-20 years	1,656	1,646
Construction in progress		13,110	6,995
		$ 632,456	$ 584,036

Depreciation expense for the year ended December 31, 2010, 2009, and 2008 was $38,085, $37,027, and $33,060, respectively, which includes amortization of fixed assets acquired under capital lease obligations of $280, $116, and $0 for 2010, 2009, and 2008; respectively. Gross assets under capital leases were $7,764 at December 31, 2010 and 2009. Accumulated amortization associated with capital leases was $396 and $116 at December 31, 2010 and 2009, respectively.

(9) GOODWILL AND OTHER INTANGIBLE ASSETS

At December 31, 2010 and 2009, goodwill balances consisted of the following:

	2010	2009
Carrying amount of goodwill:		
Terminalling and storage	$ 883	$ 883
Natural gas services	29,010	29,010
Sulfur services	5,349	5,349

Marine transportation		2,026		2,026
	$	37,268	$	37,268

Table of Contents

MARTIN MIDSTREAM PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Dollars in Thousands)

Other intangible assets subject to amortization consist of covenants not-to-compete, customer contracts associated with gathering and processing assets and a transportation contract associated with the residue gas pipeline.

The unamortized balance of other intangible assets, classified in the consolidated balance sheets as other assets, net, amounted to $17,504 and $3,103 at December 31, 2010 and 2009, respectively.

Aggregate amortization expense for amortizing intangible assets was $689, $858, and $864, for the years ended December 31, 2010, 2009 and 2008, respectively, and accumulated amortization amounted to $2,283 and $2,954 at December 31, 2010 and 2009, respectively.

Estimated amortization expenses for the years subsequent to December 31, 2010 are as follows: 2011 - $1,232; 2012 - $1,232; 2013 - $1,231; 2014 - $1,150; 2015 - $1,067; subsequent years -$11,592.

10) LEASES

The Partnership has numerous non-cancelable operating leases primarily for transportation and other equipment. The leases generally provide that all expenses related to the equipment are to be paid by the lessee. Management expects to renew or enter into similar leasing arrangements for similar equipment upon the expiration of the current lease agreements. The Partnership also has cancelable operating lease land rentals and outside marine vessel charters. Certain of our marine vessels have been acquired under capital leases.

The Partnership's future minimum lease obligations as of December 31, 2010 consist of the following:

Fiscal year	Operating Leases	Capital Leases
2011	$9,690	$1,102
2012	7,758	1,117
2013	5,918	1,135
2014	5,307	1,147
2015	5,108	1,169
Thereafter	13,398	5,582
Total	$47,179	11,252
Less amounts representing interest costs		5,080
Present value of net minimum capital lease payments		6,172
Less current installments		130
Present value of net minimum capital lease payments, excluding current installments		$6,042

Rent expense for operating leases for the years ended December 31, 2010, 2009 and 2008 was $15,710, $11,158 and $12,527; respectively. The amount recognized in interest expense for capital leases was $991, $250, and $0 for the years ended December 31, 2010, 2009 and 2008; respectively.

(11) INVESTMENT IN UNCONSOLIDATED ENTITIES AND JOINT VENTURES

The Partnership's Prism Gas subsidiary owns an unconsolidated 50% interest in Waskom, the Matagorda Offshore Gathering System ("Matagorda") and Panther Interstate Pipeline Energy LLC ("PIPE"). As a result, these assets are accounted for by the equity method.

On June 30, 2006, the Partnership's Prism Gas subsidiary, acquired a 20% ownership interest in a partnership which owns the lease rights to the assets of the Bosque County Pipeline ("BCP"). The lease contract terminated in June 2009, and, as such, the investment was fully amortized as of June 30, 2009.

Table of Contents

MARTIN MIDSTREAM PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Dollars in Thousands)

In accounting for the acquisition of the interests in Waskom, Matagorda and PIPE, the carrying amount of these investments exceeded the underlying net assets by approximately $46,176. The difference was attributable to property and equipment of $11,872 and equity method goodwill of $34,304. The excess investment relating to property and equipment is being amortized over an average life of 20 years, which approximates the useful life of the underlying assets. Such amortization amounted to $594 for the years ended December 31, 2010, 2009 and 2008, respectively, has been recorded as a reduction of equity in earnings of unconsolidated equity method investees. The remaining unamortized excess investment relating to property and equipment was $8,903, $9,497 and $10,091 at December 31, 2010, 2009 and 2008, respectively. The equity-method goodwill is not amortized; however, it is analyzed for impairment annually or if changes in circumstance indicate that a potential impairment exists. No impairment was recorded in 2010, 2009 or 2008.

As a partner in Waskom, the Partnership receives distributions in kind of natural gas liquids ("NGLs") that are retained according to Waskom's contracts with certain producers. The NGLs are valued at prevailing market prices. In addition, cash distributions are received and cash contributions are made to fund operating and capital requirements of Waskom.

Activity related to these investment accounts is as follows:

	Waskom	PIPE	Matagorda	BCP	Total
Investment in unconsolidated entities, December 31, 2008	$74,978	$1,214	$3,559	$92	$79,843
Distributions in kind	(5,826)	—	—	—	(5,826)
Distributions from unconsolidated entities	(650)	—	—	—	(650)
Contributions to unconsolidated entities:					
Cash contributions	—	90	—	—	90
Contributions to unconsolidated entities for operations	958	—	—	—	958
Return of investments	—	(490)	(375)	(12)	(877)
Equity in earnings:					
Equity in earnings (losses) from operations	6,934	602	182	(80)	7,638
Amortization of excess investment	(550)	(15)	(29)	—	(594)
Investment in unconsolidated entities, December 31 2009	$75,844	$1,401	$3,337	$-—	$80,582

	Waskom	PIPE	Matagorda	BCP	Total
Investment in unconsolidated entities, December 31, 2009	$75,844	$1,401	$3,337	$-—	$80,582
Distributions in kind	(10,545)	—	—	—	(10,545)
Contributions to unconsolidated entities:					
Cash contributions	—	—	—	—	—

Contributions to unconsolidated entities for operations	628	120	—	—	748
Cash contributions to fund asset acquisition	20,110	—	—	—	20,110
Return of investments	(2,100)	(30)	(340)	—	(2,470)
Equity in earnings:					
Equity in earnings (losses) from operations	10,381	(165)	170	—	10,386
Amortization of excess investment	(550)	(15)	(29)	—	(594)
Investment in unconsolidated entities, December 31 2010	$93,768	$1,311	$3,138	$-—	$98,217

Select financial information for significant unconsolidated equity method investees is as follows:

	As of December 31,		Years ended December 31,	
	Total Assets	Partners' Capital	Revenues	Net Income
2010				
Waskom	$ 122,057	$ 107,508	$ 123,210	$ 20,762
2009				
Waskom	$ 79,604	$ 70,561	$ 71,044	$ 13,867
2008				
Waskom	$ 78,661	$ 67,730	$ 115,031	$ 27,292

MARTIN MIDSTREAM PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Dollars in Thousands)

As of December 31, 2010 and December 31, 2009, the amount of the Partnership's consolidated retained earnings that represents undistributed earnings related to the unconsolidated equity method investees is $40,509 and $32,717, respectively. There are no material restrictions to transfer funds in the form of dividends, loans or advances related to the equity method investees.

As of December 31, 2010 and 2009, the Partnership's interest in cash of the unconsolidated equity method investees is $789 and $704, respectively.

(12) LONG-TERM DEBT AND CAPITAL LEASES

At December 31, 2010 and December 31, 2009, long-term debt consisted of the following:

	December 31, 2010	December 31,2009
** $200,000 Senior notes, 8.875% interest, net of unamortized discount of $2,543 and $0, respectively, issued March 2010 and due April 2018, unsecured	$197,457	$—
*** $275,000 Revolving loan facility at variable interest rate (4.40%* weighted average at December 31, 2010), due March 2013 secured by substantially all of the Partnership's assets, including, without limitation, inventory, accounts receivable, vessels, equipment, fixed assets and the interests in the Partnership's operating subsidiaries and equity method investees	163,000	230,251
$67,949 Term loan facility at variable interest rate (4.73%* at December 31, 2009), was terminated and converted to a revolving loan on March 26, 2010, previously secured by substantially all of the Partnership assets, which included, without limitation, inventory, accounts receivable, vessels, equipment, fixed assets and the interests in Partnership's operating subsidiaries	—	67,949
$7,354 Note payable to bank, interest rate at 7.50%, maturity date of January 2017, secured by equipment	7,354	—
Capital lease obligations	6,172	6,283
Total long-term debt and capital lease obligations	373,983	304,483
Less current installments	1,121	111
Long-term debt and capital lease obligations, net of current installments	$372,862	$304,372

* Interest rate fluctuates based on the LIBOR rate plus an applicable margin set on the date of each advance. The margin above LIBOR is set every three months. Indebtedness under the credit facility bears interest at LIBOR plus an applicable margin or the base prime rate plus an applicable margin. The applicable margin for revolving loans that are LIBOR loans ranges from 3.00% to 4.25% and the applicable margin for revolving loans that are base prime rate loans ranges from 2.00% to 3.25%. The applicable margin for existing LIBOR borrowings is 4.00%. Effective January 1, 2011, the applicable margin for existing LIBOR borrowings will remain at 4.00%. As a result of the Partnership's leverage ratio test as of December 31, 2010, effective April 1, 2011, the applicable margin for existing LIBOR borrowings will remain at 4.00% under the current credit facility.

** Effective September 2010, the Partnership entered into an interest rate swap that swapped $40,000 of fixed rate to floating rate. The floating rate cost is the applicable three-month LIBOR rate. This interest rate swap is not accounted for using hedge accounting and matures in April 2018.

MARTIN MIDSTREAM PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Dollars in Thousands)

** Effective September 2010, the Partnership entered into an interest rate swap that swapped $60,000 of fixed rate to floating rate. The floating rate cost is the applicable three-month LIBOR rate. This interest rate swap is not accounted for using hedge accounting and matures in April 2018.

*** Effective October 2008, the Partnership entered into a cash flow hedge that swapped $40,000 of floating rate to fixed rate. The fixed rate cost was 2.820% plus the Partnership's applicable LIBOR borrowing spread. Effective April 2009, the Partnership entered into two subsequent swaps to lower its effective fixed rate to 2.580% plus the Partnership's applicable LIBOR borrowing spread. These cash flow hedges were scheduled to mature in October 2010, but were terminated in March 2010.

*** Effective January 2008, the Partnership entered into a cash flow hedge that swapped $25,000 of floating rate to fixed rate. The fixed rate cost was 3.400% plus the Partnership's applicable LIBOR borrowing spread. Effective April 2009, the Partnership entered into two subsequent swaps to lower its effective fixed rate to 3.050% plus the Partnership's applicable LIBOR borrowing spread. These cash flow hedges matured in January 2010.

*** Effective September 2007, the Partnership entered into a cash flow hedge that swapped $25,000 of floating rate to fixed rate. The fixed rate cost was 4.605% plus the Partnership's applicable LIBOR borrowing spread. Effective March 2009, the Partnership entered into two subsequent swaps to lower its effective fixed rate to 4.305% plus the Partnership's applicable LIBOR borrowing spread. These cash flow hedges were scheduled to mature in September 2010, but were terminated in March 2010.

*** Effective November 2006, the Partnership entered into an interest rate swap that swapped $30,000 of floating rate to fixed rate. The fixed rate cost was 4.765% plus the Partnership's applicable LIBOR borrowing spread. This cash flow hedge matured in March 2010.

*** Effective March 2006, the Partnership entered into a cash flow hedge that swapped $75,000 of floating rate to fixed rate. The fixed rate cost was 5.25% plus the Partnership's applicable LIBOR borrowing spread. Effective February 2009, the Partnership entered into two subsequent swaps to lower its effective fixed rate to 5.10% plus the Partnership's applicable LIBOR borrowing spread. These cash flow hedges were scheduled to mature in November 2010, but were terminated in March 2010.

(a) Senior Notes

In March 2010, the Partnership and Martin Midstream Finance Corp. ("FinCo"), a subsidiary of the Partnership (collectively, the "Issuers"), entered into (i) a Purchase Agreement, dated as of March 23, 2010 (the "Purchase Agreement"), by and among the Issuers, certain subsidiary guarantors (the "Guarantors") and Wells Fargo Securities, LLC, RBC Capital Markets Corporation and UBS Securities LLC, as representatives of a group of initial purchasers (collectively, the "Initial Purchasers"), (ii) an Indenture, dated as of March 26, 2010 (the "Indenture"), among the Issuers, the Guarantors and Wells Fargo Bank, National Association, as trustee (the "Trustee") and (iii) a Registration Rights Agreement, dated as of March 26, 2010 (the "Registration Rights Agreement"), among the Issuers, the Guarantors and the Initial Purchasers, in connection with a private placement to eligible purchasers of $200,000 in aggregate principal amount of the Issuers' 8.875% senior unsecured notes due 2018 (the "Notes"). We completed the aforementioned Notes offering on March 26, 2010 and received proceeds of approximately $197,200, after deducting initial purchasers' discounts and the expenses of the private placement. The proceeds were primarily used to repay borrowings under our revolving credit facility.

On September 16, 2010, the Partnership filed a registration statement, pursuant to the registration rights agreement for the Notes issued in March 2010. The Partnership exchanged the Notes for registered 8.875% senior unsecured notes due April 2018.

In connection with the issuance of the Notes, all "non-issuer" wholly-owned subsidiaries of the Partnership issued full, irrevocable, and unconditional guarantees of the Notes. As discussed in Note 22, the Partnership does not provide separate financial statements of the Operating Partnership because the Partnership has no independent assets or operations, the guarantees are full and unconditional, and the other subsidiary of the Partnership is minor.

MARTIN MIDSTREAM PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Dollars in Thousands)

Indenture.

Interest and Maturity. On March 26, 2010, the Issuers issued the Notes pursuant to the Indenture in a transaction exempt from registration requirements under the Securities Act. The Notes were resold to qualified institutional buyers pursuant to Rule 144A under the Securities Act and to persons outside the United States pursuant to Regulation S under the Securities Act. The Notes will mature on April 1, 2018. The interest payment dates are April 1 and October 1, beginning on October 1, 2010.

Optional Redemption. Prior to April 1, 2013, the Issuers have the option on any one or more occasions to redeem up to 35% of the aggregate principal amount of the Notes issued under the Indenture at a redemption price of 108.875% of the principal amount, plus accrued and unpaid interest, if any, to the redemption date of the Notes with the proceeds of certain equity offerings. Prior to April 1, 2014, the Issuers may on any one or more occasions redeem all or a part of the Notes at the redemption price equal to the sum of (i) the principal amount thereof, plus (ii) a make whole premium at the redemption date, plus accrued and unpaid interest, if any, to the redemption date. On or after April 1, 2014, the Issuers may on any one or more occasions redeem all or a part of the Notes at redemption prices (expressed as percentages of principal amount) equal to 104.438% for the twelve-month period beginning on April 1, 2014, 102.219% for the twelve-month period beginning on April 1, 2015 and 100.00% for the twelve-month period beginning on April 1, 2016 and at any time thereafter, plus accrued and unpaid interest, if any, to the applicable redemption date on the Notes.

Certain Covenants. The Indenture restricts the Partnership’s ability and the ability of certain of its subsidiaries to: (i) sell assets including equity interests in its subsidiaries; (ii) pay distributions on, redeem or repurchase its units or redeem or repurchase its subordinated debt; (iii) make investments; (iv) incur or guarantee additional indebtedness or issue preferred units; (v) create or incur certain liens; (vi) enter into agreements that restrict distributions or other payments from its restricted subsidiaries to us; (vii) consolidate, merge or transfer all or substantially all of its assets; (viii) engage in transactions with affiliates; (ix) create unrestricted subsidiaries; (x) enter into sale and leaseback transactions or (xi) engage in certain business activities. These covenants are subject to a number of important exceptions and qualifications. If the Notes achieve an investment grade rating from each of Moody’s Investors Service, Inc. and Standard & Poor’s Ratings Services and no Default (as defined in the Indenture) has occurred and is continuing, many of these covenants will terminate.

Events of Default. The Indenture provides that each of the following is an Event of Default: (i) default for 30 days in the payment when due of interest on the Notes; (ii) default in payment when due of the principal of, or premium, if any, on the Notes; (iii) failure by the Partnership to comply with certain covenants relating to asset sales, repurchases of the Notes upon a change of control and mergers or consolidations; (iv) failure by the Partnership for 180 days after notice to comply with its reporting obligations under the Securities Exchange Act of 1934; (v) failure by the Partnership for 60 days after notice to comply with any of the other agreements in the Indenture; (vi) default under any mortgage, indenture or instrument governing any indebtedness for money borrowed or guaranteed by the Partnership or any of its restricted subsidiaries, whether such indebtedness or guarantee now exists or is created after the date of the Indenture, if such default: (a) is caused by a payment default; or (b) results in the acceleration of such indebtedness prior to its stated maturity, and, in each case, the principal amount of the indebtedness, together with the principal amount of any other such indebtedness under which there has been a payment default or acceleration of maturity, aggregates $20,000 or more, subject to a cure provision; (vii) failure by the Partnership or any of its restricted subsidiaries to pay final judgments aggregating in excess of $20,000, which judgments are not paid, discharged or stayed for a period of 60 days; (viii) except as permitted by the Indenture, any subsidiary guarantee is held in any judicial proceeding to be unenforceable or invalid or ceases for any reason to be in full force or effect, or any Guarantor, or any person acting on behalf of any Guarantor, denies or disaffirms its obligations under its subsidiary guarantee and (ix) certain events of bankruptcy, insolvency or reorganization described in the Indenture with respect to the Issuers or any of the Partnership's restricted subsidiaries that is a significant subsidiary or any group of restricted subsidiaries that, taken together, would constitute a significant subsidiary of the Partnership. Upon a continuing Event of Default, the Trustee, by notice to the Issuers, or the holders of at least 25% in principal amount of the then outstanding Notes, by notice to the Issuers and the Trustee, may declare the Notes immediately due and payable, except that an Event of Default resulting from entry into a bankruptcy, insolvency or reorganization with respect to the Issuers, any restricted subsidiary of the Partnership that is a significant subsidiary or any group of its restricted subsidiaries that, taken together, would constitute a significant subsidiary of the Partnership, will automatically cause the Notes to become due and payable.

Table of Contents

MARTIN MIDSTREAM PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Dollars in Thousands)

Registration Rights Agreement. Under the Registration Rights Agreement, the Issuers and the Guarantors filed with the SEC, a registration statement with respect to an offer to exchange the Notes for substantially identical notes that are registered under the Securities Act. Pursuant to the registration rights agreement for the Senior Notes issued in March 2010, the Partnership filed an exchange offer registration statement on September 16, 2010. The Partnership exchanged the Notes for registered 8.875% senior unsecured notes due April 2018.

(b) Credit Facility

On November 10, 2005, the Partnership entered into a $225,000 multi-bank credit facility comprised of a $130,000 term loan facility and a $95,000 revolving credit facility, which included a $20,000 letter of credit sub-limit. Effective September 30, 2006, the Partnership increased its revolving credit facility by $25,000, resulting in a committed $120,000 revolving credit facility. Effective December 28, 2007, the Partnership increased its revolving credit facility by $75,000, resulting in a committed $195,000 revolving credit facility. Effective December 21, 2009, (i) the Partnership increased its revolving credit facility by approximately $72,722, resulting in a committed $267,722 revolving credit facility and (ii) decreased its term loan facility by approximately $62,051, resulting in a $67,949 term loan facility. Effective January 14, 2010, the Partnership modified its revolving credit facility to (i) permit investment up to $25,000 in joint ventures and (ii) limit its ability to make capital expenditures. Effective February 25, 2010, the Partnership increased the maximum amount of borrowings and letters of credit available under its credit facility from approximately $335,671 to $350,000. Effective March 26, 2010, the Partnership's credit facility was amended and restated to (i) decrease the size of its aggregate facility from $350,000 to $275,000, (ii) convert all term loans to revolving loans, (iii) extend the maturity date from November 9, 2012 to March 15, 2013, (iv) permit the Partnership to invest up to $40,000 in its joint ventures, (v) eliminate the covenant that limits its ability to make capital expenditures, (vi) decrease the applicable interest rate margin on committed revolver loans, (vii) limit its ability to make future acquisitions and (viii) adjust the financial covenants.

Under the amended and restated credit facility, as of December 31, 2010, the Partnership had $163,000 outstanding under the revolving credit facility. As of December 31, 2010, irrevocable letters of credit issued under the Partnership's credit facility totaled $120.

As of December 31, 2010, the Partnership had $111,880 available under its revolving credit facility. The revolving credit facility is used for ongoing working capital needs and general partnership purposes, and to finance permitted investments, acquisitions and capital expenditures. During the current fiscal year, draws on the Partnership's credit facility ranged from a low of $80,000 to a high of $324,500.

The Partnership's obligations under the credit facility are secured by substantially all of the Partnership's assets, including, without limitation, inventory, accounts receivable, vessels, equipment, fixed assets and the interests in its operating subsidiaries and equity method investees. The Partnership may prepay all amounts outstanding under this facility at any time without penalty.

In addition, the credit facility contains various covenants, which, among other things, limit the Partnership's ability to: (i) incur indebtedness; (ii) grant certain liens; (iii) merge or consolidate unless it is the survivor; (iv) sell all or substantially all of its assets; (v) make certain acquisitions; (vi) make certain investments; (vii) make certain capital expenditures; (viii) make distributions other than from available cash; (ix) create obligations for some lease payments; (x) engage in transactions with affiliates; (xi) engage in other types of business and (xii) incur indebtedness or grant certain liens through its joint ventures.

The credit facility includes financial covenants that are tested on a quarterly basis, based on the rolling four-quarter period that ends on the last day of each fiscal quarter. Prior to the Partnership's or any of its subsidiaries' issuance of $100,000 or more of unsecured indebtedness, the maximum permitted leverage ratio is 4.00 to 1.00. After the Partnership or any of its subsidiaries' issuance of $100,000 or more of unsecured indebtedness, the maximum permitted leverage ratio is 4.50 to 1.00. After the Partnership or any of its subsidiaries' issuance of $100,000 or more of unsecured indebtedness, the maximum permitted senior leverage ratio (as defined in the new credit facility, but generally computed as the ratio of total secured funded debt to consolidated earnings before interest, taxes, depreciation, amortization and certain other non-cash charges) is 2.75 to 1.00. The minimum consolidated interest coverage ratio (as defined in the new credit facility, but generally computed as the ratio of consolidated earnings before interest, taxes, depreciation, amortization and certain other non-cash charges to consolidated interest charges) is 3.00 to 1.00. The Partnership was in compliance with the covenants contained in the credit facility as of December 31, 2010.

MARTIN MIDSTREAM PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Dollars in Thousands)

The credit facility also contains certain default provisions relating to Martin Resource Management. If Martin Resource Management no longer controls the Partnership's general partner, or if Ruben Martin is not the chief executive officer of our general partner or a successor acceptable to the administrative agent and lenders providing more than 50% of the commitments under our credit facility is not appointed, the lenders under the Partnership's credit facility may declare all amounts outstanding thereunder immediately due and payable. In addition, an event of default by Martin Resource Management under its credit facility could independently result in an event of default under the Partnership's credit facility if it is deemed to have a material adverse effect on the Partnership. Any event of default and corresponding acceleration of outstanding balances under the Partnership's credit facility could require the Partnership to refinance such indebtedness on unfavorable terms and would have a material adverse effect on the Partnership's financial condition and results of operations as well as its ability to make distributions to unitholders.

The Partnership is required to make certain prepayments under the credit facility. If the Partnership receives greater than $15,000 from the incurrence of indebtedness other than under the credit facility, it must prepay indebtedness under the credit facility with all such proceeds in excess of $15,000. The Partnership must prepay revolving loans under the credit facility with the net cash proceeds from any issuance of its equity. The Partnership must also prepay indebtedness under the credit facility with the proceeds of certain asset dispositions. Other than these mandatory prepayments, the credit facility requires interest only payments on a quarterly basis until maturity. All outstanding principal and unpaid interest must be paid by March 15, 2013. The credit facility contains customary events of default, including, without limitation, payment defaults, cross-defaults to other material indebtedness, bankruptcy-related defaults, change of control defaults and litigation-related defaults.

The Partnership paid cash interest in the amount of $23,663, $18,291, and $18,744 for the years ended December 31, 2010, 2009, and 2008, respectively. Capitalized interest was $130, $259, and $1,383 for the years ended December 31, 2010, 2009, and 2009, respectively. In March 2010, the Partnership terminated all of its then outstanding interest rate swaps resulting in termination fees of $3,850.

(13) DERIVATIVE INSTRUMENTS AND HEDGING ACTIVITIES

The Partnership's results of operations are materially impacted by changes in crude oil, natural gas and natural gas liquids prices and interest rates. In an effort to manage our exposure to these risks, we periodically enter into various derivative instruments, including commodity and interest rate hedges. We are required to recognize all derivative instruments as either assets or liabilities at fair value on our Consolidated Balance Sheets and to recognize certain changes in the fair value of derivative instruments on our Consolidated Statements of Operations.

The Partnership performs, at least quarterly, a retrospective assessment of the effectiveness of our hedge contracts, including assessing the possibility of counterparty default. If we determine that a derivative is no longer expected to be highly effective, we discontinue hedge accounting prospectively and recognize subsequent changes in the fair value of the hedge in earnings. As a result of our effectiveness assessment at December 31, 2010, we believe certain hedge contracts will continue to be effective in offsetting changes in cash flow or fair value attributable to the hedged risk.

All derivatives and hedging instruments are included on the balance sheet as an asset or a liability measured at fair value and changes in fair value are recognized currently in earnings unless specific hedge accounting criteria are met. If a derivative qualifies for hedge accounting, changes in the fair value can be offset against the change in the fair value of the hedged item through earnings or recognized in accumulated other comprehensive income ("AOCI") until such time as the hedged item is recognized in earnings. The Partnership is exposed to the risk that periodic changes in the fair value of derivatives qualifying for hedge accounting will not be effective, as defined, or that derivatives will no longer qualify for hedge accounting. To the extent that the periodic changes in the fair value of the derivatives are not effective, that ineffectiveness is recorded to earnings. Likewise, if a hedge ceases to qualify for hedge accounting, any change in the fair value of derivative instruments since the last period is recorded to earnings; however, any amounts previously recorded to AOCI would remain there until such time as the original forecasted transaction occurs, then would be reclassified to earnings or if it is determined that continued reporting of losses in AOCI would lead to recognizing a net loss on the combination of the hedging instrument and the hedge transaction in future periods, then the losses would be immediately reclassified to earnings.

MARTIN MIDSTREAM PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Dollars in Thousands)

For derivative instruments that are designated and qualify as cash flow hedges, the effective portion of the gain or loss on the derivative is reported as a component of accumulated other comprehensive income and reclassified into earnings in the same period during which the hedged transaction affects earnings. The effective portion of the derivative represents the change in fair value of the hedge that offsets the change in fair value of the hedged item. To the extent the change in the fair value of the hedge does not perfectly offset the change in the fair value of the hedged item, the ineffective portion of the hedge is immediately recognized in earnings.

In March 2008, the FASB amended the provisions of ASC Topic 820 related to fair value measurements and disclosures, which changes the disclosure requirements for derivative instruments and hedging activities. Entities are required to provide enhanced disclosures about (1) how and why an entity uses derivative instruments, (2) how derivative instruments and related hedged items are accounted for and (3) how derivative instruments and related hedged items affect an entity’s financial position, financial performance and cash flows. The Partnership adopted this guidance on January 1, 2009.

Commodity Derivative Instruments

The Partnership is exposed to market risks associated with commodity prices and uses derivatives to manage the risk of commodity price fluctuation. The Partnership has established a hedging policy and monitors and manages the commodity market risk associated with its commodity risk exposure. The Partnership has entered into hedging transactions through 2012 to protect a portion of its commodity exposure. These hedging arrangements are in the form of swaps for crude oil, natural gas, and natural gasoline. In addition, the Partnership is focused on utilizing counterparties for these transactions whose financial condition is appropriate for the credit risk involved in each specific transaction.

Due to the volatility in commodity markets, the Partnership is unable to predict the amount of ineffectiveness each period, including the loss of hedge accounting, which is determined on a derivative by derivative basis. This may result, and has resulted in increased volatility in the Partnership’s financial results. Factors that have and may continue to lead to ineffectiveness and unrealized gains and losses on derivative contracts include: a substantial fluctuation in energy prices, the number of derivatives the Partnership holds, and significant weather events that have affected energy production. The number of instances in which the Partnership has discontinued hedge accounting for specific hedges is primarily due to those reasons. However, even though these derivatives may not qualify for hedge accounting, the Partnership continues to hold the instruments as it believes they continue to afford the Partnership opportunities to manage commodity risk exposure.

As of December 31, 2010 and 2009, the Partnership has both derivative instruments qualifying for hedge accounting with fair value changes being recorded in AOCI as a component of partners’ capital and derivative instruments not designated as hedges being marked to market with all market value adjustments being recorded in earnings.

Set forth below is the summarized notional amount and terms of all instruments held for price risk management purposes at December 31, 2010 (all gas quantities are expressed in British Thermal Units, crude oil and natural gas liquids are expressed in barrels). As of December 31, 2010, the remaining term of the contracts extend no later than December 2012, with no single contract longer than one year. For the years ended December 31, 2010, and 2009, changes in the fair value of the Partnership’s derivative contracts were recorded in both earnings and in AOCI as a component of partners’ capital.

Table of Contents

MARTIN MIDSTREAM PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Dollars in Thousands)

Transaction Type	Total Volume Per Month	Pricing Terms	Remaining Terms of Contracts		Fair Value
Mark to Market Derivatives::					
Crude Oil Swap	2,000 BBL	Fixed price of $91.20 settled against WTI NYMEX average monthly closings	January 2011 to December 2011		(51)
Total commodity swaps not designated as hedging instruments				$	(51)
Cash Flow Hedges:					
Natural Gas Swap	10,000 Mmbtu	Fixed price of $6.1250 settled against IF_ANR_LA first of the month posting	January 2011 to December 2011		201
Natural Gas Swap	20,000 Mmbtu	Fixed price of $4.3225 settled against IF_ANR_LA first of the month posting	January 2011 to December 2011		(28)
Natural Gasoline Swap	2,000 BBL	Fixed price of $87.10 settled against WTI NYMEX average monthly closings	January 2011 to December 2011		(149)
Natural Gasoline Swap	1,000 BBL	Fixed price of $88.85 settled against WTI NYMEX average monthly closings	January 2011 to December 2011		(54)
Crude Oil Swap	2,000 BBL	Fixed price of $88.63 settled against WTI NYMEX average monthly closings	January 2012 to December 2012		(126)
Natural Gasoline Swap	1,000 BBL	Fixed price of $90.20 settled against WTI NYMEX average monthly closings	January 2012 to December 2012		(44)
Total commodity swaps designated as hedging instruments				$	(200)
Total net fair value of commodity derivatives				$	(251)

Based on estimated volumes, as of December 31, 2010, the Partnership had hedged approximately 37% and 10% of its commodity risk by volume for 2011 and 2012, respectively. As of March 2, 2011, Prism Gas has hedged approximately 45% and 14% of its commodity risk by volume for 2011 and 2012, respectively.

The Partnership anticipates entering into additional commodity derivatives on an ongoing basis to manage its risks associated with these market fluctuations, and will consider using various commodity derivatives, including forward contracts, swaps, collars, futures and options, although there is no assurance that the Partnership will be able to do so or that the terms thereof will be similar to the Partnership's existing hedging arrangements.

The Partnership's credit exposure related to commodity cash flow hedges is represented by the positive fair value of contracts to the Partnership at December 31, 2010. These outstanding contracts expose the Partnership to credit loss in the event of nonperformance by the counterparties to the agreements. The Partnership has incurred no losses associated with counterparty nonperformance on derivative contracts.

On all transactions where the Partnership is exposed to counterparty risk, the Partnership analyzes the counterparty's financial condition prior to entering into an agreement, establishes a maximum credit limit threshold pursuant to its hedging policy, and monitors the appropriateness of these limits on an ongoing basis. The Partnership has agreements with five counterparties containing collateral provisions. Based on those current agreements, cash deposits are required to be posted whenever the net fair value of derivatives associated with the individual counterparty exceed a specific threshold. If this threshold is exceeded, cash is posted by the Partnership if the value of derivatives is a liability to the Partnership. As of December 31, 2010 the Partnership has no cash collateral deposits posted with counterparties.

The Partnership's principal customers with respect to Prism Gas' natural gas gathering and processing are large, natural gas marketing services, oil and gas producers and industrial end-users. In addition, substantially all of the Partnership's natural gas and NGL sales are made at market-based prices. The Partnership's standard gas and NGL sales contracts contain adequate assurance provisions which allows for the suspension of deliveries, cancellation of agreements or discontinuance of deliveries to the buyer unless the buyer provides security for payment in a form satisfactory to the Partnership.

MARTIN MIDSTREAM PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Dollars in Thousands)

Impact of Commodity Cash Flow Hedges

Crude Oil

For the years ended December 31, 2010, 2009 and 2008, net gains and losses on swap hedge contracts increased crude revenue by $27, decreased crude revenue by $854 and increased crude revenue by $1,745, respectively. As of December 31, 2010 an unrealized derivative fair value gain of $634 related to current and terminated cash flow hedges of crude oil price risk was recorded in AOCI. Fair value gains of $760 and fair value losses of $126 are expected to be reclassified into earnings in 2011 and 2012, respectively. The actual reclassification to earnings for contracts remaining in effect will be based on mark-to-market prices at the contract settlement date or for those terminated contracts based on the recorded values at December 31, 2010 adjusted for any impairment, along with the realization of the gain or loss on the related physical volume, which is not reflected above.

Natural Gas

For the years ended December 31, 2010, 2009 and 2008, net gains and losses on swap hedge contracts increased gas revenue by $601 and $1,824 and decreased gas revenue by $431, respectively. As of December 31, 2010 an unrealized derivative fair value gain of $158 related to cash flow hedges of natural gas was recorded in AOCI. This fair value gain is expected to be reclassified into earnings in 2011. The actual reclassification to earnings will be based on mark-to-market prices at the contract settlement date, along with the realization of the gain or loss on the related physical volume, which is not reflected above.

Natural Gas Liquids

For the years ended December 31, 2010, 2009 and 2008, net gains and losses on swap hedge contracts increased liquids revenue by $207 and decreased liquids revenue by $186 and $316, respectively. As of December 31, 2010, an unrealized derivative fair value gain of $645 related to current and terminated cash flow hedges of natural gas liquids price risk was recorded in AOCI. Fair value gains of $689 and fair value losses of $44 are expected to be reclassified into earnings in 2011 and 2012, respectively. The actual reclassification to earnings for contracts remaining in effect will be based on mark-to-market prices at the contract settlement date or for those terminated contracts based on the recorded values at December 31, 2010 adjusted for any impairment, along with the realization of the gain or loss on the related physical volume, which is not reflected above.

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

Interest Rate Derivative Instruments

The Partnership is exposed to market risks associated with interest rates. The Partnership enters into interest rate swaps to manage interest rate risk associated with the Partnership’s variable rate debt and term loan credit facilities. All derivatives and hedging instruments are included on the balance sheet as an asset or a liability measured at fair value and changes in fair value are recognized currently in earnings unless specific hedge accounting criteria are met. If a derivative qualifies for hedge accounting, changes in the fair value can be offset against the change in the fair value of the hedged item through earnings or recognized in AOCI until such time as the hedged item is recognized in earnings.

The Partnership has entered into interest rate swap agreements with an aggregate notional amount of $100,000 to hedge its exposure to changes in the fair value of Senior Notes. The Partnership believes the interest rate hedge contracts will be effective in offsetting changes in fair value attributable to the hedged risk; however, the contracts were not designated as fair value hedges and therefore, are not receiving hedge accounting but being marked to market through earnings.

Table of Contents

MARTIN MIDSTREAM PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Dollars in Thousands)

Under the following swap agreements, the Partnership pays a floating rate of interest and receives a fixed rate based on a three-month U.S. Dollar LIBOR rate to match the fixed rate of the Senior Notes:

Date of Hedge	Notional Amount	Paying Floating Rate	Receiving Fixed Rate	Maturity Date
September 2010	$ 40,000	3 Month LIBOR	2.3150 %	April 2018
September 2010	$ 60,000	3 Month LIBOR	2.3150 %	April 2018

In March 2010, in connection with a pay down of the Partnership's revolving credit facility, the Partnership terminated all of its existing cash flow hedge agreements with an aggregate notional amount of $140,000 which it had entered to hedge its exposure to increases in the benchmark interest rate underlying its variable rate revolving and term loan credit facilities. Termination fees of $3,850 were paid on early extinguishment of all interest rate swap agreements in March 2010. The amounts remaining in AOCI will be reclassified into interest expense over the original term of the terminated interest rate derivatives.

The Partnership recognized increases in interest expense of $6,327 and $7,892 for the years ended December 31, 2010 and 2009, respectively, related to the difference between the fixed rate and the floating rate of interest on the interest rate swap and net cash settlement of interest rate swaps and hedges.

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

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

The following table summarizes the fair values and classification of our derivative instruments in our Consolidated Balance Sheet:

	Fair Values of Derivative Instruments in the Consolidated Balance Sheet					
	Derivative Assets			Derivative Liabilities		
		Fair Values December 31,			Fair Values December 31,	
	Balance Sheet Location	2010	2009	Balance Sheet Location	2010	2009
Derivatives designated as hedging instruments:	Current Assets:			Current Liabilities:		
Interest rate contracts	Fair value of derivatives	$ —	$ —	Fair value of derivatives	$ —	$ 923
Commodity contracts	Fair value of derivatives	201	311	Fair value of derivatives	230	—
		201	311		230	923

	Non-current Assets:			Non-current Liabilities:		
Interest rate contracts	Fair value of derivatives	—	—	Fair value of derivatives	—	—
Commodity contracts	Fair value of derivatives	—	—	Fair value of derivatives	171	—
		—	—		171	—
Total derivatives designated as hedging instruments		$ 201	$ 311		$ 401	$ 923

Table of Contents

MARTIN MIDSTREAM PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Dollars in Thousands)

Fair Values of Derivative Instruments in the Consolidated Balance Sheet

	Derivative Assets			Derivative Liabilities		
		Fair Values December 31,			Fair Values December 31,	
	Balance Sheet Location	2010	2009	Balance Sheet Location	2010	2009
Derivatives not designated as hedging instruments:	Current Assets:			Current Liabilities:		
Interest rate contracts	Fair value of derivatives	$ 1,941	$ 1,286	Fair value of derivatives	$ —	$ 5,688
Commodity contracts	Fair value of derivatives	—	275	Fair value of derivatives	51	616
		1,941	1,561		51	6,304
	Non-current Assets:			Non-current Liabilities:		
Interest rate contracts	Fair value of derivatives	—	—	Fair value of derivatives	3,930	—
Commodity contracts	Fair value of derivatives	—	—	Fair value of derivatives	—	—
		—	—		3,930	—
Total derivatives not designated as hedging instruments		$ 2,142	$ 1,561		$ 3,981	$ 6,304

Effect of Derivative Instruments on the Consolidated Statement of Operations
For the Years Ended December 31, 2010, 2009 and 2008

	Effective Portion			Ineffective Portion and Amount Excluded from Effectiveness Testing	
	Amount of Gain or (Loss) Recognized in OCI on Derivatives	Location of Gain or (Loss) Reclassified from Accumulated OCI into Income	Amount of Gain or (Loss) Reclassified from Accumulated OCI into Income	Location of Gain or (Loss) Recognized in Income on Derivatives	Amount of Gain or (Loss) Recognized in Income on Derivatives

	2010	2009	2008		2010	2009	2008		2010	2009	2008
Derivatives designated as hedging instruments											
Interest rate contracts	(241)	$(1,854)	$(5,435)	Interest Expense	$(4,210)	$(7,345)	$—	Interest Expense	$—	$—	$—
Commodity contracts	143	14	4,219	Natural Gas Services Revenues	547	2,667	(2,819)	Natural Gas Services Revenues	70	(21)	(224)
Total derivatives designated as hedging instruments	$(98)	$(1,840)	$1,216		$(3,663)	$(4,678)	$(2,819)		$ 70	$(21)	$(224)

- 106 -

Table of Contents

MARTIN MIDSTREAM PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Dollars in Thousands)

	Location of Gain or (Loss) Recognized in Income on Derivatives	Amount of Gain or (Loss) Recognized in Income on Derivatives		
		2010	2009	2008
Derivatives not designated as hedging instruments				
Interest rate contracts	Interest Expense	$(2,117)	$(547)	$(1,052)
Commodity contracts	Natural Gas Services Revenues	219	(1,863)	4,041
Total derivatives not designated as hedging instruments		$(1,898)	$(2,410)	$2,989

Amounts expected to be reclassified into earnings for the subsequent twelve month period are losses of $18 for interest rate cash flow hedges and gains of $1,608 for commodity cash flow hedges.

(14) RELATED PARTY TRANSACTIONS

As of December 31, 2010, Martin Resource Management owns 5,703,823 of the Partnership’s common units and 889,444 subordinated units collectively representing approximately 35.5% of the Partnership’s outstanding limited partnership units. The Partnership’s general partner is a wholly-owned subsidiary of Martin Resource Management. The Partnership’s general partner owns a 2.0% general partner interest in the Partnership and the Partnership’s incentive distribution rights. The Partnership’s general partner’s ability, as general partner, to manage and operate the Partnership, and Martin Resource Management’s ownership as of December 31, 2010 of approximately 35.5% of the Partnership’s outstanding limited partnership units, effectively gives Martin Resource Management the ability to veto some of the Partnership’s actions and to control the Partnership’s management.

The following is a description of the Partnership’s material related party transactions:

Omnibus Agreement

Omnibus Agreement. The Partnership and its general partner are parties to an omnibus agreement dated November 1, 2002 with Martin Resource Management that governs, among other things, potential competition and indemnification obligations among the parties to the agreement, related party transactions, the provision of general administration and support services by Martin Resource Management and our use of certain of Martin Resource Management’s trade names and trademarks. The omnibus agreement was amended on November 24, 2009 to include processing crude oil into finished products including naphthenic lubricants, distillates, asphalt and other intermediate cuts.

Non-Competition Provisions. Martin Resource Management has agreed for so long as it controls our general partner, not to engage in the business of:

- providing terminalling, refining, processing, distribution and midstream logistical services for hydrocarbon products and by-products;
- providing marine and other transportation of hydrocarbon products and by-products; and
- manufacturing and marketing fertilizers and related sulfur-based products.

This restriction does not apply to:

- the ownership and/or operation on our behalf of any asset or group of assets owned by us or our affiliates;
    - any business operated by Martin Resource Management, including the following:
        - providing land transportation of various liquids,

MARTIN MIDSTREAM PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Dollars in Thousands)

- distributing fuel oil, sulfuric acid, marine fuel and other liquids,
- providing marine bunkering and other shore-based marine services in Alabama, Louisiana, Mississippi and Texas,
- operating a small crude oil gathering business in Stephens, Arkansas,
- operating an underground NGL storage facility in Arcadia, Louisiana,
- building and marketing sulfur processing equipment, and
- developing an underground natural gas storage facility in Arcadia, Louisiana;

- any business that Martin Resource Management acquires or constructs that has a fair market value of less than $5.0 million;
- any business that Martin Resource Management acquires or constructs that has a fair market value of $5.0 million or more if the Partnership has been offered the opportunity to purchase the business for fair market value, and the Partnership declines to do so with the concurrence of the conflicts committee; and
- any business that Martin Resource Management acquires or constructs where a portion of such business includes a restricted business and the fair market value of the restricted business is $5.0 million or more and represents less than 20% of the aggregate value of the entire business to be acquired or constructed; provided that, following completion of the acquisition or construction, the Partnership will be provided the opportunity to purchase the restricted business.

Services. Under the omnibus agreement, Martin Resource Management provides us with corporate staff, support services, and administrative services necessary to operate our business. The omnibus agreement requires us to reimburse Martin Resource Management for all direct expenses it incurs or payments it makes on our behalf or in connection with the operation of our business. There is no monetary limitation on the amount the Partnership is required to reimburse Martin Resource Management for direct expenses. In addition to the direct expenses, Martin Resource Management is entitled to reimbursement for a portion of indirect general and administrative and corporate overhead expenses. Under the omnibus agreement, the Partnership is required to reimburse Martin Resource Management for indirect general and administrative and corporate overhead expenses.

Effective October 1, 2010 through September 30, 2011, the Conflicts Committee of the board of directors of our general partner (the “Conflicts Committee”) approved an annual reimbursement amount for indirect expenses of $4.2 million. We reimbursed Martin Resource Management for $3.8, $3.5, and $2.9 million of indirect expenses for the years ending December 31, 2010, 2009, and 2008, respectively. The Conflicts Committee will review and approve future adjustments in the reimbursement amount for indirect expenses, if any, annually.

These indirect expenses are intended to cover the centralized corporate functions Martin Resource Management provides for us, such as accounting, treasury, clerical billing, information technology, administration of insurance, general office expenses and employee benefit plans and other general corporate overhead functions the Partnership shares with Martin Resource Management retained businesses. The provisions of the omnibus agreement regarding Martin Resource Management’s services will terminate if Martin Resource Management ceases to control our general partner.

Related Party Transactions. The omnibus agreement prohibits us from entering into any material agreement with Martin Resource Management without the prior approval of the conflicts committee of our general partner’s board of directors. For purposes of the omnibus agreement, the term material agreements means any agreement between the Partnership and Martin Resource Management that requires aggregate annual payments in excess of then-applicable agreed upon reimbursable amount of indirect general and administrative expenses. Please read “— Services” above.

MARTIN MIDSTREAM PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Dollars in Thousands)

License Provisions. Under the omnibus agreement, Martin Resource Management has granted us a nontransferable, nonexclusive, royalty-free right and license to use certain of its trade names and marks, as well as the trade names and marks used by some of its affiliates.

Amendment and Termination. The omnibus agreement may be amended by written agreement of the parties; provided, however that it may not be amended without the approval of the conflicts committee of our general partner if such amendment would adversely affect the unitholders. The omnibus agreement was amended on November 24, 2009 to permit us to provide refining services to Martin Resource Management. Such amendment was approved by the conflicts committee of our general partner. The omnibus agreement, other than the indemnification provisions and the provisions limiting the amount for which the Partnership will reimburse Martin Resource Management for general and administrative services performed on our behalf, will terminate if the Partnership is no longer an affiliate of Martin Resource Management.

Motor Carrier Agreement

Motor Carrier Agreement. The Partnership is a party to a motor carrier agreement effective January 1, 2006 with Martin Transport, Inc., a wholly owned subsidiary of Martin Resource Management through which Martin Resource Management operates its land transportation operations. This agreement replaced a prior agreement effective November 1, 2002 between us and Martin Transport, Inc. for land transportation services. Under the agreement, Martin Transport Inc. agreed to ship our NGL shipments as well as other liquid products.

Term and Pricing. This agreement was amended in November 2006, January 2007, April 2007 and January 2008 to add additional point-to-point rates and to modify certain fuel and insurance surcharges being charged to the Partnership. The agreement has an initial term that expired in December 2007 but automatically renews for consecutive one-year periods unless either party terminates the agreement by giving written notice to the other party at least 30 days prior to the expiration of the then-applicable term. The Partnership has the right to terminate this agreement at anytime by providing 90 days prior notice. Under this agreement, Martin Transport, Inc. transports the Partnership's NGL shipments as well as other liquid products. These rates are subject to any adjustment to which are mutually agreed or in accordance with a price index. Additionally, during the term of the agreement, shipping charges are also subject to fuel surcharges determined on a weekly basis in accordance with the U.S. Department of Energy's national diesel price list.

Marine Agreements

Marine Transportation Agreement. The Partnership is a party to a marine transportation agreement effective January 1, 2006, which was amended January 1, 2007, under which the Partnership provides marine transportation services to Martin Resource Management on a spot-contract basis at applicable market rates. This agreement replaced a prior agreement effective November 1, 2002 between the Partnership and Martin Resource Management covering marine transportation services which expired November 2005. Effective each January 1, this agreement automatically renews for consecutive one-year periods unless either party terminates the agreement by giving written notice to the other party at least 60 days prior to the expiration of the then applicable term. The fees the Partnership charges Martin Resource Management are based on applicable market rates.

Cross Marine Charter Agreements. Cross entered into four marine charter agreements with the Partnership effective March 1, 2007. These agreements have an initial term of five years and continue indefinitely thereafter subject to cancellation after the initial term by either party upon a 30 day written notice of cancellation. The charter hire payable under these agreements will be adjusted annually to reflect the percentage change in the Consumer Price Index.

Marine Fuel. The Partnership is a party to an agreement with Martin Resource Management under which Martin Resource Management provides the Partnership with marine fuel from its locations in the Gulf of Mexico at a fixed rate over the Platt's U.S. Gulf Coast Index for #2 Fuel Oil. Under this agreement, the Partnership agreed to purchase all of its marine fuel requirements that occur in the areas serviced by Martin Resource Management.

Table of Contents

MARTIN MIDSTREAM PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Dollars in Thousands)

Terminal Services Agreements

Diesel Fuel Terminal Services Agreement. The Partnership is a party to an agreement under which the Partnership provides terminal services to Martin Resource Management. This agreement was amended and restated as of October 27, 2004 and was set to expire in December 2006, but automatically renewed and will continue to automatically renew on a month-to-month basis until either party terminates the agreement by giving 60 days written notice. The per gallon throughput fee we charge under this agreement may be adjusted annually based on a price index.

Miscellaneous Terminal Services Agreements. The Partnership is currently party to several terminal services agreements and from time to time the Partnership may enter into other terminal service agreements for the purpose of providing terminal services to related parties. Individually, each of these agreements is immaterial but when considered in the aggregate they could be deemed material. These agreements are throughput based with a minimum volume commitment. Generally, the fees due under these agreements are adjusted annually based on a price index.

Other Agreements

Cross Tolling Agreement. We are party to an agreement under which we process crude oil into finished products, including naphthenic lubricants, distillates, asphalt and other intermediate cuts for Cross. The Tolling Agreement has a 12 year term which expires November 24, 2021. Under this Tolling Agreement, Martin Resource Management agreed to refine a minimum of 6,500 barrels per day of crude oil at the refinery at a fixed price per barrel. Any additional barrels are refined at a modified price per barrel. In addition, Martin Resource Management agreed to pay a monthly reservation fee and a periodic fuel surcharge fee based on certain parameters specified in the Tolling Agreement. All of these fees (other than the fuel surcharge) are subject to escalation annually based upon the greater of 3% or the increase in the Consumer Price Index for a specified annual period. In addition, every three years, the parties can negotiate an upward or downward adjustment in the fees subject to their mutual agreement.

Sulfuric Acid Sales Agency Agreement. The Partnership is party to an agreement under which Martin Resource Management purchases and markets the sulfuric acid produced by the Partnership’s sulfuric acid production plant at Plainview, Texas, and which is not consumed by the Partnership’s internal operations. This agreement, which was amended and restated in August 2008, will remain in place until the Partnership terminates it by providing 180 days’ written notice. Under this agreement, the Partnership sells all of its excess sulfuric acid to Martin Resource Management. Martin Resource Management then markets such acid to third-parties and the Partnership shares in the profit of Martin Resource Management’s sales of the excess acid to such third parties.

Other Miscellaneous Agreements. From time to time the Partnership enters into other miscellaneous agreements with Martin Resource Management for the provision of other services or the purchase of other goods.

The tables below summarize the related party transactions that are included in the related financial statement captions on the face of the Partnership’s Consolidated Statements of Operations. The revenues, costs and expenses reflected in these tables are tabulations of the related party transactions that are recorded in the corresponding caption of the consolidated financial statement and do not reflect a statement of profits and losses for related party transactions.

The impact of related party revenues from sales of products and services is reflected in the consolidated financial statement as follows:

Revenues:	2010	2009	2008
Terminalling and storage	$46,823	$19,998	$18,362
Marine transportation	28,194	19,370	24,956
Product sales:			
Natural gas services	7,686	238	4,024

MARTIN MIDSTREAM PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Dollars in Thousands)

Sulfur services	7,146	5,445	22,631
Terminalling and storage	166	155	49
	14,998	5,838	26,704
	$90,015	$45,206	$70,022

The impact of related party cost of products sold is reflected in the consolidated financial statement as follows:

Cost of products sold:			
Natural gas services	$79,321	$56,914	$92,322
Sulfur services	16,061	12,583	13,282
Terminalling and storage	298	287	533
	$95,680	$69,784	$106,137

The impact of related party operating expenses is reflected in the consolidated financial statement as follows:

Operating expenses			
Marine transportation	$26,730	$20,464	$22,586
Natural gas services	2,245	1,491	1,625
Sulfur services	5,271	4,496	3,737
Terminalling and storage	15,040	10,833	9,713
	$49,286	$37,284	$37,661

The impact of related party selling, general and administrative expenses is reflected in the consolidated financial statement as follows:

Selling, general and administrative:			
Natural gas services	$4,729	$1,116	$880
Sulfur services	2,398	2,504	2,508
Indirect overhead allocation, net of reimbursement	3,791	3,542	2,896
	$10,918	$7,162	$6,284

On December 22, 2010, the Partnership acquired a 60,000 bbl offshore tank barge from Martin Resource Management for a total purchase price of $17,000. The Partnership paid cash in the amount of $9,600 and assumed a note payable to a third party for $7,400. The net book value of the acquired assets was $16,805 and was recorded in property, plant, and equipment. The remaining $195 was recorded as a distribution to Martin Resource Management.

On August 26, 2010, the Partnership acquired certain shore-based marine terminalling assets from Martin Resource Management for $11,700. The net book value of the acquired assets was $7,331 and was recorded in property, plant and equipment. The remaining $4,369 was recorded as a distribution to Martin Resource Management. These assets are located in Theodore, Alabama and Pascagoula, Mississippi.

The amount of related party interest expense reflected in the consolidated financial statement is $0, $872 and $1,656 for the years ending December 31, 2010, 2009 and 2008, respectively.

(15) PARTNERS' CAPITAL

As of December 31, 2010, partners' capital consists of 17,707,832 common limited partner units, representing a 93.3% partnership interest, 889,444 subordinated limited partner units, representing 4.7% partnership interest and a 2% general partner interest. Martin Resource Management through a subsidiary, owned an approximate 34.7% limited partnership interest consisting of 5,703,823 common limited partner units and 889,444 subordinated limited partner units and a 2% general partner interest.

MARTIN MIDSTREAM PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Dollars in Thousands)

The Partnership Agreement contains specific provisions for the allocation of net income and losses to each of the partners for purposes of maintaining their respective partner capital accounts.

Distributions of Available Cash

The Partnership distributes all of its Available Cash (as defined in the Partnership Agreement) within 45 days after the end of each quarter to unitholders of record and to the general partner. Available Cash is generally defined as all cash and cash equivalents of the Partnership on hand at the end of each quarter less the amount of cash reserves its general partner determines in its reasonable discretion is necessary or appropriate to: (i) provide for the proper conduct of the Partnership's business; (ii) comply with applicable law, any debt instruments or other agreements; or (iii) provide funds for distributions to unitholders and the general partner for any one or more of the next four quarters, plus all cash on the date of determination of available cash for the quarter resulting from working capital borrowings made after the end of the quarter.

(16) GAIN ON DISPOSAL OF ASSETS

On April 30, 2009, the Partnership sold certain assets comprising the Mont Belvieu railcar unloading facility, which yielded net proceeds from the sale in the amount of $19,610. The assets sold related to twenty railcar spaces and a newly constructed major expansion that had not been placed in operation. The disposition was comprised of property, plant and equipment and allocated goodwill included in the Partnership's terminalling segment with an aggregate carrying value of $14,329. This transaction yielded a gain on the sale of property, plant, and equipment in the amount of $5,281. The gain is included in "other operating income" in the consolidated statement of operations for the year ending December 31, 2009.

In September 2010, the Partnership received $349 from an indemnity escrow. The gain is included in "other operating income" in the consolidated statement of operations for the year ending December 31, 2010. Additionally, the Partnership expects to receive payment of $375 in April 2012, which represents payment from an indemnity escrow resulting from the sale. The Partnership expects to record this amount as a gain in the respective quarter. The Partnership paid down the outstanding revolving loans under its credit facility with the net cash proceeds from this sale of assets. The amount paid down is available for future borrowings under the revolving credit facility.

(17) GAIN ON INVOLUNTARY CONVERSION OF ASSETS

During the third quarter of 2008, several of the Partnership's facilities in the Gulf of Mexico were in the path of two major hurricanes, Hurricane Gustav and Hurricane Ike. Physical damage to the Partnership's assets caused by the hurricanes, as well as the related removal and recovery costs, are covered by insurance subject to a deductible. Losses incurred as a result of a single hurricane (an "occurrence") are limited to a maximum aggregate deductible of $250 for flood damage and $1,000 minimum plus 2% of total insured value at each location for wind damage. The partnership's total flood coverage is $15,000 and total wind coverage is $100,000.

The most significant damage to the Partnership's assets was sustained at the Neches location. Property damage also occurred at the Partnership's Galveston, Sabine Pass, Intracoastal City, Cameron East, Cameron West, Freeport, Venice, Port Fourchon, Stanolind, Mont Belvieu, and Spindletop locations. Based on an analysis of the damage as performed by the Partnership estimated its non-cash charge as $1,207 for all locations which is equal to the net-book value of the damaged assets. A receivable was established for the expected insurance recovery equal to the impairment charge and for all expenditures related to water damage less the for mentioned deductible.

The Partnership recognized a $1,207 estimated loss during the last half of 2008, which approximates the Partnership's hurricane deductible under its applicable insurance policies, incurred as a result of Hurricanes Gustav and Ike. The loss is included in "operating expenses" in the consolidated statement of operations for the year ended December 31, 2008.

Table of Contents

MARTIN MIDSTREAM PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Dollars in Thousands)

Insurance proceeds received as a result of the aforementioned claims exceeded net book value of the Partnership's assets determined to be impaired. During 2009, the Partnership received insurance proceeds of $2,224 for this involuntary conversion of assets, which resulted in a gain of $1,017 which is reported in other operating income.

(18) INCOME TAXES

The operations of a partnership are generally not subject to income taxes, except as discussed below, because its income is taxed directly to its partners. Effective January 1, 2007, the Partnership is subject to the Texas margin tax as described below. Woodlawn, a subsidiary of the Partnership, is subject to income taxes due to its corporate structure. A current federal income tax benefit of $ 0 and $1,061 and a current federal income tax expense of $239, related to the operation of the subsidiary, were recorded for the years ended December 31, 2010, 2009 and 2008, respectively. In connection with the Woodlawn acquisition, the Partnership also established deferred income taxes of $8,964 associated with book and tax basis differences of the acquired assets and liabilities. The basis differences are primarily related to property, plant and equipment.

The activities of the Cross assets prior to the acquisition by the Partnership were subject to federal and state income taxes. Accordingly, income taxes have been included in the Cross assets operating results for 2008 and the period from January 1, 2009 through November 24, 2009. Related payables/receivables are included in Due to affiliates and Other current assets, respectively, on the consolidated balance sheet.

A deferred tax benefit of $415 and a deferred tax expense of $294 and $2,442 related to the Woodlawn basis differences and the basis differences of the Cross assets was recorded for the years ended December 31, 2010, 2009 and 2008, respectively. A deferred tax liability of $ 8,213 and $8,628 related to these basis differences existed at December 31, 2010 and 2009, respectively. A deferred tax asset related to the activities of the Cross assets of $165 is included in Other current assets at December 31, 2008.

In 2006, the Texas Governor signed into law a Texas margin tax (H.B. No. 3) which restructures the state business tax by replacing the taxable capital and earned surplus components of the current franchise tax with a new "taxable margin" component. Since the tax base on the Texas margin tax is derived from an income-based measure, the margin tax is construed as an income tax and, therefore, the recognition of deferred taxes applies to the new margin tax. The impact on deferred taxes as a result of this provision is immaterial. State income taxes attributable to the Texas margin tax of $932, $422 and $749 were recorded in income tax expense for the years ended December 31, 2010, 2009 and 2008, respectively.

An income tax receivable of $760 is included in Other current assets at December 31, 2010 and 2009. An income tax liability of $811, $454 and $414 existed at December 31, 2010, 2009 and 2008, respectively.

The components of income tax expense (benefit) from operations recorded for the years ended December 31, 2010, 2009 and 2008 are as follows:

	2010	2009	2008
Current:			
Federal	$—	$(311)	$(1,879)
State	932	609	835
	932	298	(1,044)

Deferred:			
Federal	(415)	294	2,442
	$517	$592	$1,398

(19) BUSINESS SEGMENTS

The Partnership has four reportable segments: terminalling and storage, natural gas services, marine transportation, and sulfur services. The Partnership's reportable segments are strategic business units that offer different products and services. The operating income of these segments is reviewed by the chief operating decision maker to assess performance and make business decisions.

Table of Contents

MARTIN MIDSTREAM PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Dollars in Thousands)

The accounting policies of the operating segments are the same as those described in Note 2 of the Notes to Consolidated Financial Statements. The Partnership evaluates the performance of its reportable segments based on operating income. There is no allocation of administrative expenses or interest expense.

	Operating Revenues	Intersegment Eliminations	Operating Revenues After Eliminations	Depreciation and Amortization	Operating Income (Loss) after Eliminations	Capital Expenditures
Year ended December 31, 2010:						
Terminalling and storage	$119,270	$ (4,354)	$ 114,916	$ 16,650	$ 14,256	$ 6,996
Natural gas services	554,482	—	554,482	5,023	5,616	1,645
Sulfur services	165,078	—	165,078	6,262	20,166	7,107
Marine transportation	82,635	(4,993)	77,642	12,721	6,524	2,159
Indirect selling, general, and administrative	—	—	—	—	(6,386)	—
Total	$921,465	$ (9,347)	$ 912,118	$ 40,656	$ 40,176	$ 17,907
Year ended December 31, 2009:						
Terminalling and storage	$109,513	$ (4,219)	$ 105,294	$ 15,717	$ 17,899	$ 18,404
Natural gas services	408,989	(7)	408,982	4,527	5,666	5,010
Sulfur services	79,631	(2)	79,629	6,151	13,776	7,909
Marine transportation	72,103	(3,623)	68,480	13,111	3,156	4,523
Indirect selling, general, and administrative	—	—	—	—	(6,077)	—
Total	$670,236	$ (7,851)	$ 662,385	$ 39,506	$ 34,420	$ 35,846
Year ended December 31, 2008:						
Terminalling and storage	$122,960	$ (4,189)	$ 118,771	$ 12,947	$ 11,399	$ 31,439
Natural gas services	679,375	—	679,375	4,067	3,725	9,565
Sulfur services	372,987	(1,038)	371,949	5,751	37,180	6,884
Marine transportation	80,059	(3,710)	76,349	12,128	5,570	53,562
Indirect selling, general, and administrative	—	—	—	—	(5,510)	—
Total	$1,255,381	$ (8,937)	$ 1,246,444	$ 34,893	$ 52,364	$ 101,450

The following table reconciles operating income to net income:

Year Ended December 31,

	2010	2009	2008
Operating income	$40,176	$34,420	$52,364
Equity in earnings of unconsolidated entities	9,792	7,044	13,224
Interest expense	(33,716)	(18,995)	(21,433)
Other, net	287	326	801
Income taxes	(517)	(592)	(1,398)
Net income	$16,022	$22,203	$43,558

Revenues from one customer in the Natural gas services segment were $92,265, $72,492 and $103,424 for the years ended December 31, 2010, 2009 and 2008, respectively.

Total assets by segment at December 31, 2010 and 2009 are as follows:

	2010	2009
Total assets:		
Terminalling and storage	$ 188,234	$ 178,941
Natural gas services	314,815	256,397
Sulfur services	138,224	110,953

Table of Contents

MARTIN MIDSTREAM PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Dollars in Thousands)

	2010	2009
Marine transportation	144,205	139,648
Total assets	$ 785,478	$ 685,939

Investments in unconsolidated entities totaled $98,217 and $80,582 at December 31, 2010 and 2009, respectively, and are included in the natural gas services segment.

(20) QUARTERLY FINANCIAL INFORMATION

CONSOLIDATED QUARTERLY INCOME STATEMENT INFORMATION

	(Unaudited)			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(Dollar in thousands, except per unit amounts)			
2010				
Revenues	$ 242,676	$ 211,944	$ 195,387	$ 262,141
Operating Income	7,563	9,102	7,703	15,808
Equity in earnings of unconsolidated entities	2,176	2,342	2,951	2,323
Net income	1,771	3,075	4,636	6,540
Net income per limited partner unit [2]	$ 0.04	$ 0.10	$ 0.19	$ 0.30

	First[1] Quarter	Second[1] Quarter	Third[1] Quarter	Fourth[1] Quarter
	(Dollar in thousands, except per unit amounts)			
2009				
Revenues	$ 163,051	$ 139,201	$ 159,272	$ 200,861
Operating Income	7,906	15,958	6,062	4,494
Equity in earnings of unconsolidated entities	2,059	1,028	2,139	1,818
Net income	5,213	10,760	4,274	1,956
Net income per limited partner unit [2]	$ 0.28	$ 0.48	$ 0.26	$ 0.13

	First[1] Quarter	Second[1] Quarter	Third[1] Quarter	Fourth[1] Quarter
	(Dollar in thousands, except per unit amounts)			
2008				
Revenues	$ 318,839	$ 318,649	$ 372,856	$