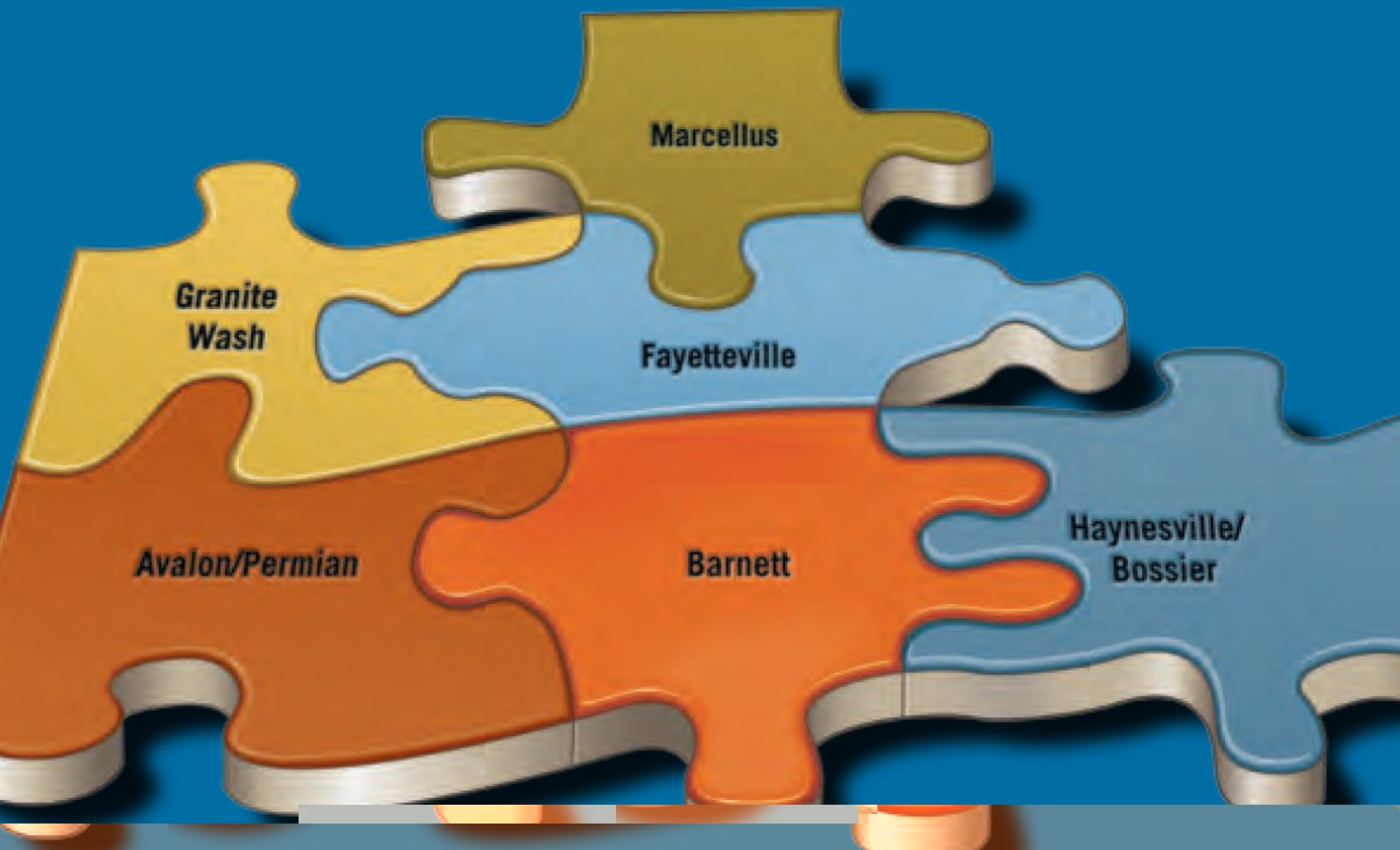
Crestwood
MIDSTREAM PARTNERS LP

2011 Annual Report

Building the Foundation for Long Term Growth



Shale Gas Plays

Source: Energy Information Administration

Crestwood Midstream Partners LP is building a foundation for long term growth by executing its shale focused strategy through the acquisition and development of midstream assets in selected shale or unconventional resource plays. By diversifying Crestwood's portfolio from its origins in the Barnett Shale, we have enhanced our customer and geographic base and positioned the partnership for long term growth in volumes, revenues and distributions. We will continue to look for unique investment opportunities in emerging shale plays that require midstream infrastructure.

Contents

Crestwood Midstream Partners LP (Crestwood or CMLP) is managed by its General Partner, Crestwood Gas Services GP LLC, which is owned and managed by Crestwood Holdings Partners, LLC (Crestwood Holdings), a partnership formed in 2010 between First Reserve and the Crestwood management team. We are a Delaware master limited partnership with our common units trading on the New York Stock Exchange (NYSE) under the ticker symbol CMLP.

Cover: *Through March 2012, Crestwood owns and operates gathering, processing, treating and compression assets located in the the Avalon Shale in southeast New Mexico, the Barnett Shale in north Texas, the Haynesville/Bossier Shale in western Louisiana, the Fayetteville Shale in northwest Arkansas, the Granite Wash in the Texas Panhandle and the Marcellus Shale in northern West Virginia.*

2011 Accomplishments

Established Crestwood as an independent, fast growing, shale-focused MLP

Produced impressive year over year growth: gathering volumes + 66%, adjusted EBITDA + 44%, adjusted distributable cash flow + 39%, distributions declared per unit + 13%

Completed $414 million of acquisitions expanding into four new geographic regions (the $375 million Antero Marcellus acquisition was completed in March 2012)

Raised $215 million of equity and $200 million of debt in successful capital market transactions

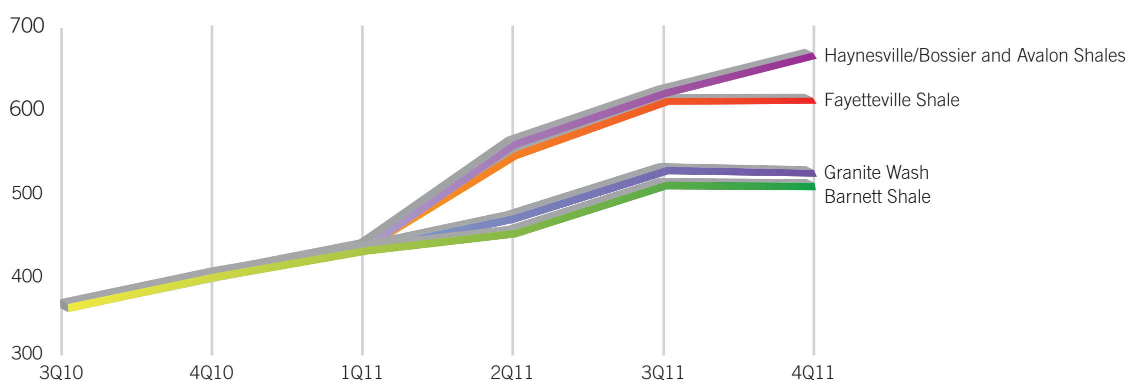
Delivered total unitholder returns of 23%

Financial and Operating Highlights

Crestwood Midstream Partners LP
(Dollar amounts in thousands, except per unit data)

Year ended December 31	2008	2009	2010	**2011**
Statement of Operations Data				
Total revenues	$ 76,084	$ 95,881	$113,590	**$ 205,820**
Adjusted EBITDA	50,293	64,238	76,549	**109,962**
Adjusted net income	26,142	32,499	42,748	**49,782**
Weighted average number of limited partner units outstanding (diluted basis)	29,583	28,189	31,316	**37,320**
Balance Sheet Data				
Total assets	$502,606	$487,624	$570,627	**$1,026,892**
Long-term debt	174,900	125,400	283,504	**512,500**
Partners' capital	115,208	284,837	258,753	**455,623**
Other Financial Data				
Adjusted distributable cash flow	$ 47,079	$ 51,260	$ 63,301	**$ 87,825**
Cash distributions declared per unit	$ 1.39	$ 1.52	$ 1.66	**$ 1.87**
Operating Data				
Gathering (MMcf)	70,617	93,955	125,317	**208,146**
Processing (MMcf)	56,225	54,386	46,660	**52,613**

Gathering Volumes (MMcfd)



When Crestwood Holdings acquired CMLP's general partner interest in October 2010, the Board of Directors laid out a clear strategy to focus on shale and unconventional natural gas resource plays and create a diversified portfolio of growth oriented midstream assets with limited exposure to commodity volatility. Including the October 2010 acquisition, we have completed five acquisitions with a total transaction value of approximately $1.5 billion. With these acquisitions we have established a platform that positions Crestwood as an industry leader in shale-play infrastructure. This platform represents a unique MLP investment opportunity in the gathering and processing peer group with a contract portfolio that is approximately 95% fixed-fee. Our footprint in many of the industry's top-tier shale plays was achieved through the close collaboration between Crestwood's management and our general partner sponsor, First Reserve Corporation, an experienced world-class investor in energy infrastructure.

Standing, left to right

John W. Somerhalder II

Timothy H. Day

Michael G. France

Robert G. Phillips
Chairman, President and CEO

J. Hardy Murchison

Joel C. Lambert

Philip W. Cook

Seated, left to right

Philip D. Gettig

Alvin Bledsoe

Building the Foundation for Long Term Growth

Crestwood's investment strategy is based upon the potential for decades of future shale play developments requiring new midstream infrastructure. We are optimistic about the role that abundant sources of natural gas and natural gas liquids (NGLs) will play in the growth of North American and global energy markets. In 2011, Crestwood evolved from a Barnett Shale-only midstream service provider into a high-growth entity servicing a broad range of successful shale developers in the industry's leading unconventional natural gas plays. Relying on our 30+ years of experience acquiring and integrating midstream assets, we have built a scalable, shale-based organization, quickly integrating acquisitions and enhancing our asset and producer portfolios. Executing this strategy has paid benefits to CMLP unitholders in 2011 with record operating performance from a balanced mix of rich and dry gas assets with visible long-term growth potential.

CMLP's first expansion outside of the Barnett Shale came in February 2011, with the acquisition of the Las Animas System in southeastern New Mexico. This system is well positioned to grow with the development of the Avalon Shale, an emerging rich-gas play in the resurgent Permian Basin. Based on drilling results in 2011, the Avalon Shale is expected to hold significant resources of liquids-rich natural gas which offer opportunities for CMLP to provide additional gathering and processing services.

In April 2011, CMLP acquired gathering and treating assets in the Fayetteville Shale, located in northwestern Arkansas, and gathering and processing assets in the Granite Wash, located in the Texas Panhandle. Despite the dry gas characteristics of the Fayetteville Shale, producers have consistently improved well performance through increasingly efficient operations. This trend is expected to support continued development even in the current low natural gas price environment. Over the long-term, our systems are well positioned to benefit from long-term contract dedications of over 100,000 acres in core areas of the play from producers including BHP Billiton, BP and XTO/ExxonMobil. The Granite Wash play, like the Avalon Shale, is a rich-gas region with substantial producer activity. While not a significant contributor to gathering volumes in 2011, our Granite Wash gathering and processing system has experienced modest development by producers including Chesapeake and Great Plains and has the potential for significant expansion as drilling activity increases.

In November 2011, CMLP diversified into the Haynesville Shale, the industry's leading natural gas shale play by production volume, with the acquisition of the Sabine System in western Louisiana. This acquisition further expanded our customer portfolio including Chesapeake, Forest Oil, Devon Energy and Comstock Resources. While low natural gas prices may delay near-term development, the Sabine System's connections to the Gulf South and Tennessee Gas pipelines provide access to attractive downstream markets which enabled us to sign a firm agreement with a third-party supplier that supplements gathering volumes in 2012.

Growing Barnett Shale Contribution in 2011

While strategic acquisitions expanded CMLP's portfolio and improved its long-term outlook, our Barnett Shale assets made a major contribution to CMLP's record operating performance in 2011, with increased gathering volumes of 38% over 2010. CMLP's rich-gas Cowtown System remained our most profitable asset, and when combined with our Granite Wash System, these rich-gas assets contributed approximately 50% of CMLP's revenues for the year. The Cowtown area is expected to be the primary focus of Quicksilver Resources' Barnett Shale development plan in 2012. While considered a relatively mature shale play, peak production was just reached in November 2011 and local producers estimate that the play is only 50% developed. With significant gathering and processing capacity in place, CMLP is well positioned to handle additional volumes as the field is further developed.

Expanding the Crestwood Platform in 2012

In March 2012, we completed the acquisition of Marcellus Shale gathering assets from Antero Resources through a joint venture between CMLP and Crestwood Holdings. This key acquisition established CMLP as a strong competitor in the premier shale-play in the United States and significantly increased our investment in rich-gas development areas. CMLP indirectly owns a 35% interest and operates the joint venture, with Crestwood Holdings indirectly owning the remaining interest. The acquisition includes a 20-year dedication of 127,000 core Marcellus Shale acres under a fixed-fee gathering contract with annual rate escalators. The transaction also includes a seven year minimum volume commitment supporting our investment.

With First Reserve's participation, the joint venture enabled CMLP to make a meaningful investment in a leading shale-play while maintaining a conservatively financed balance sheet. As the system expands, potential drop-down acquisitions from the joint venture provide CMLP with visible growth opportunities.

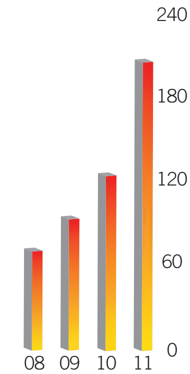
Taking Stock; Looking Forward

Having established CMLP as a premier shale-play MLP in 2011, we are focused on operational excellence and developing our assets. I want to congratulate our operations team for its impressive safety record in 2011 and thank our organization for its commitment to the communities where we live and work. CMLP's expansion into the Marcellus Shale and continued development of our Cowtown, Las Animas and Granite Wash systems should benefit the partnership as producers shift activity to rich-gas areas that benefit from high NGL prices. Over the long-term, our large, core acreage dedications in world-class shale plays should drive continued volume growth as producers develop their acreage. Enhanced by First Reserve's sponsorship, CMLP is well positioned for consistent, long-term growth. On behalf of the Board of Directors, I want to thank our investors for their support in 2011 and we look forward to continued success in 2012 and beyond.

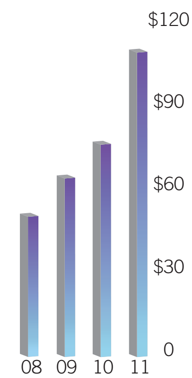
Robert G. Phillips

Chairman, President and CEO
Crestwood Gas Services GP LLC,
the General Partner of Crestwood Mistream Partners LP

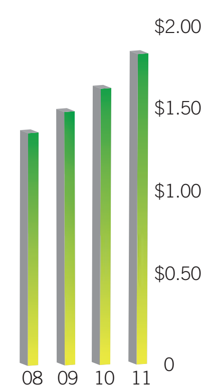
Gathering Volumes
(Bcf)



Adjusted EBITDA
($MM)



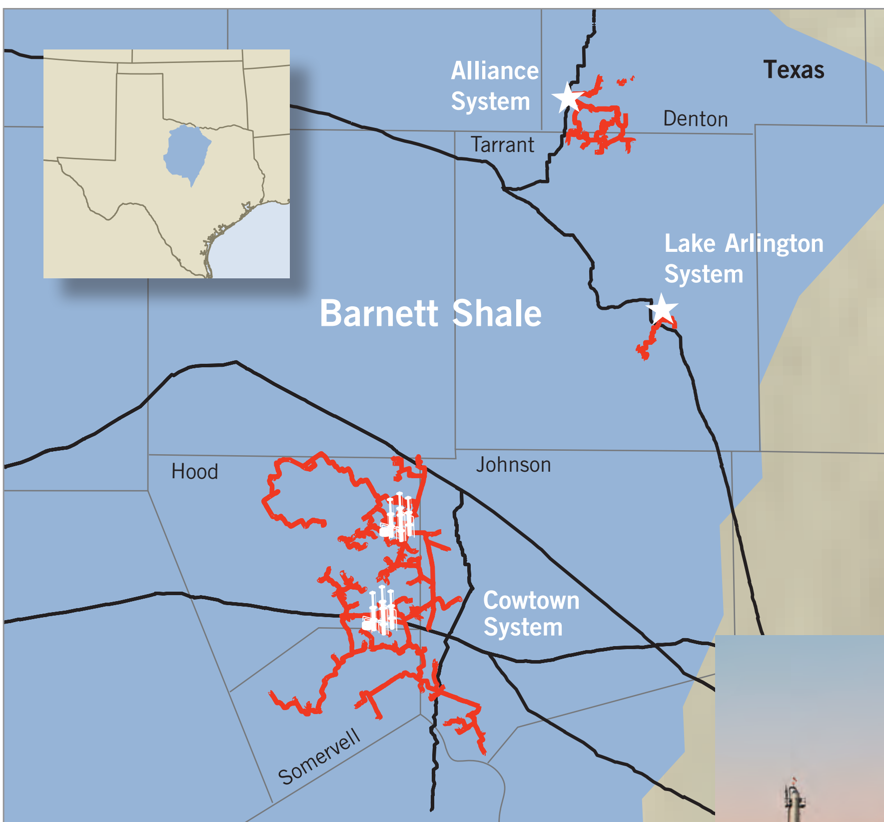
Distributions Declared
($ Per Unit)



Barnett Shale:

Cowtown, Alliance and Lake Arlington gathering systems

The Barnett Shale is considered to be the shale-play where the unconventional gas industry was born. Now the second largest shale play by volume, the Barnett Shale has been in steady development since 2005. CMLP's assets consist of three separate gathering systems anchored by a total dedication of approximately 122,000 acres under fixed-fee contracts which extend to 2020. The Cowtown System, which includes two high recovery gas processing plants, contributed approximately 50% of our total Barnett segment gross margin in 2011. The Cowtown System is located in the "liquids-rich" southwestern portion of the Barnett Shale where we gather and process natural gas from more than 600 wells and third-party interconnects. The NGLs contained in the gas stream in the Cowtown area provide our customers with significant value and supports continued drilling activity in 2012 despite low natural gas prices. The Alliance and Lake Arlington Systems gather dry-gas from over 300 wells and are located in the "core" producing areas of the play. These wells have benefitted from increasing recoverable reserves and higher initial production rates due to longer laterals and improved fracture stimulation. In 2011, we connected 138 new wells to our Barnett Shale systems and increased third-party volumes from Chesapeake, Devon and Empire, leading to average gathering volumes of 474 million cubic feet per day (MMcfd), a 38% increase over 2010.



Crestwood pipelines

Third-party natural gas and NGL take away pipelines

Processing facility

Compression and treating facility

Attributes[1]

Geologic Basin
Fort Worth

Formation
Barnett Shale

Area (square miles)
5,000

Estimated Shale Gas Production Through 2011
8.7 Tcf (Trillion cubic feet)

Approximate 2011 Production
5.4 Bcfd (Billion cubic feet per day)

Technically Recoverable Resource Estimate
43.4 Tcf

Approximate Number of Wells Drilled
14,000

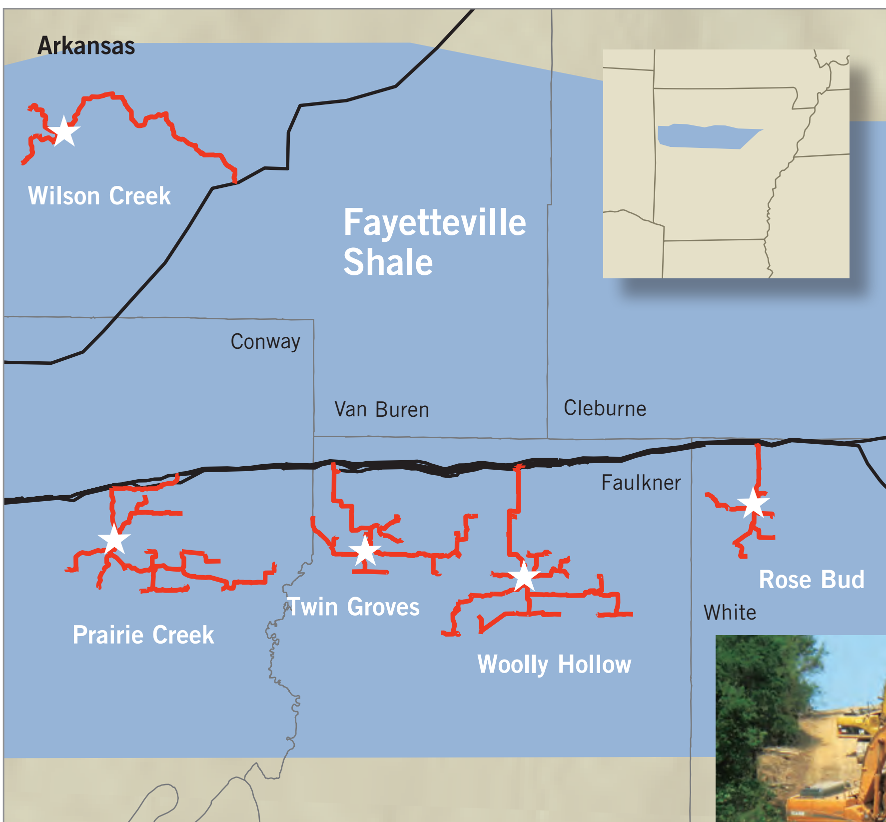
Crestwood's Alliance station located in Denton County, Texas, provides treating, dehydration and compression of natural gas at a capacity of up to 300 MMcfd using 42,000 HP of efficient and reliable electric-driven compression.

(1) Sources: Energy Information Administration, Bentek Energy and Wood Mackenzie

Fayetteville Shale:

Fayetteville gathering systems

The Fayetteville Shale, located in northwest Arkansas, covers approximately 4,000 square miles and contains an estimated 32 Tcf of potential recoverable gas reserves. Crestwood owns and operates five separate gathering systems in Conway, Faulkner, White and Van Buren counties that are considered to be in the core of the Fayetteville Shale producing region. Our contracts cover approximately 100,000 acres of production dedication by BHP Billiton and BP that extend to 2024. The systems gather, treat for CO_2 and compress gas production into downstream interstate pipelines including Ozark, Boardwalk and Fayetteville Express. We acquired the Fayetteville Shale assets to add another large-scale acreage development opportunity to our portfolio that is supported by world-class reserves and long-term, fixed-fee contracts with large, experienced shale producers. Recent well completions have confirmed higher expected ultimate recoveries and production rates compared to our acquisition analysis which we expect will result in modest 2012 volume growth. Over the long-term, BHP's substantial $4.75 billion initial investment in the Fayetteville Shale and higher forecasted natural gas prices in the years ahead should drive future development and offer Crestwood growth in volumes and cash flow from this important long-term asset.



Crestwood pipelines

Third-party natural gas and NGL take away pipelines

Compression and treating facility

Attributes[1]

Geologic Basin
Arkoma

Formation
Fayetteville Shale

Area (square miles)
4,000

Estimated Shale Gas Production Through 2011
2.7 Tcf

Approximate 2011 Production
2.8 Bcfd

Technically Recoverable Resource Estimate
32.0 Tcf

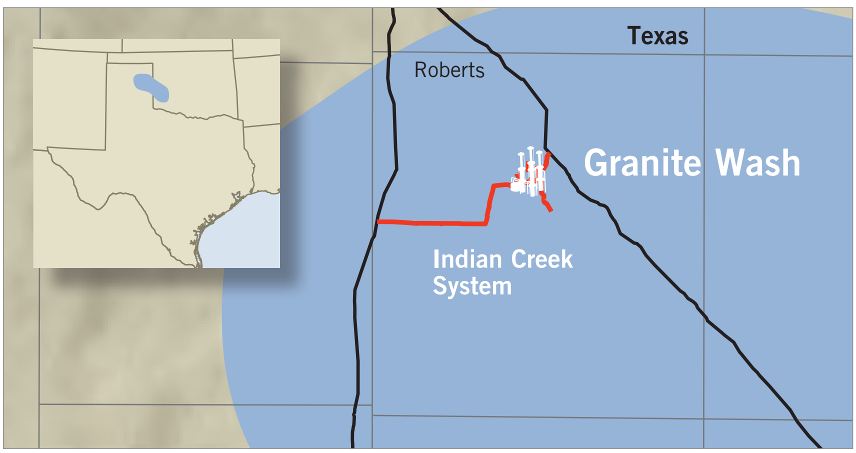
Crestwood's connection of its Prairie Creek system to the Fayetteville Express Pipeline, completed during the fourth quarter of 2011, provides our customers with additional market access.

(1) Sources: Energy Information Administration, Bentek Energy and Wood Mackenzie

Granite Wash and Avalon Shale:

Indian Creek and Las Animas gathering systems

The Indian Creek System in the Texas Panhandle is located within the Granite Wash region of the Anadarko basin which has seen a resurgence in the redevelopment of old, conventional rich-gas plays through horizontal drilling and fracture stimulation. The region has benefitted from a substantial increase in new infrastructure projects keeping pace with volume increases which has also led to a competitive environment and aggressive contracting for midstream services. CMLP's 31-mile pipeline system is supported by approximately 13,000 acres of production dedication with contracts which extend through 2022. NGLs extracted at CMLP's 36 MMcfd Indian Creek cryogenic processing plant are connected to the Mid-America Pipeline, providing area producers with direct access to the premium priced Mont Belvieu, Texas, NGL market. We believe our assets are well positioned for long-term growth as producers begin to develop properties in the area of our system.



Attributes[1]

Geologic Basin
Anadarko

Formation
Granite Wash

Area (square miles)
1,250

Estimated Shale Gas Production Through 2011
2.9 Tcf

Approximate 2011 Production
1.6 Bcfd

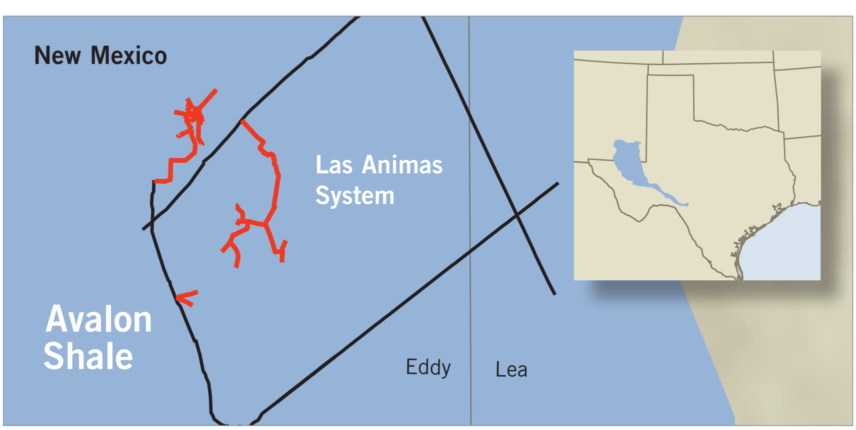
Technically Recoverable Resource Estimate
16.3 Tcf

Crestwood pipelines

Third-party natural gas and NGL take away pipelines

Processing facility

CMLP acquired its Avalon Shale assets as a low-cost option to an emerging oil and rich-gas play on the western side of the resurgent Delaware and Permian Basins. Locally called the Leonard Shale in southeast New Mexico, the region includes developments targeting the Bone Spring, Wolfcamp and Wolfbone unconventional oil formations where advanced drilling and completion techniques have improved producer economics. CMLP's Las Animas System provides traditional dry-gas gathering from the Morrow Atoka reservoir for area producers such as Bass Enterprises. In the past year, Devon, Bass and Chesapeake have commenced Avalon Shale developments in areas overlapping our current system footprint. To capture the value of the rich-gas content, substantial midstream infrastructure to increase NGL takeaway capacity will need to be built to accommodate future rich-gas development. Announced third-party pipeline projects that are expected to be completed over the next two years should alleviate this bottleneck. CMLP's Las Animas System is well positioned to participate in the potential growth of this emerging play.



Attributes[1]

Geologic Basin
Delaware (Permian region)

Area Plays
Avalon Shale / Bone Springs

Resource
Rich-gas and oil

Status
Emerging development

Crestwood pipelines

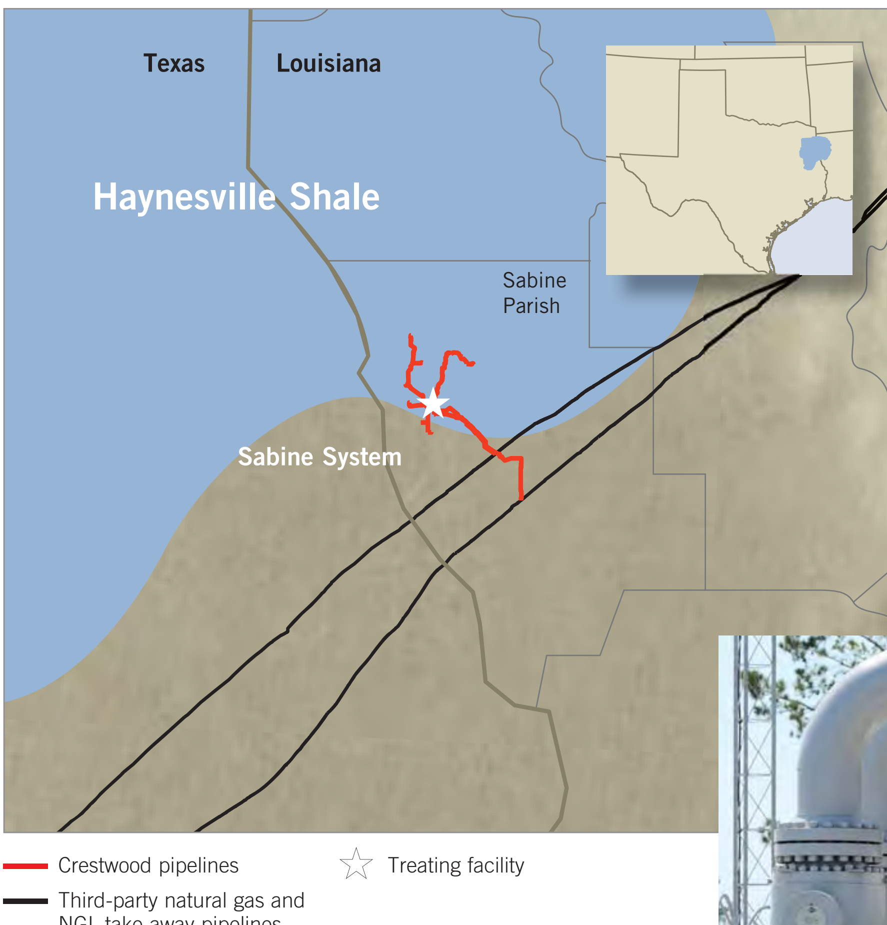
Third-party natural gas and NGL take away pipelines

(1) Sources: Energy Information Administration, Bentek Energy and Wood Mackenzie

Haynesville/Bossier Shale:

Sabine System

The Haynesville and Middle Bossier Shale, extending throughout east Texas and northwest Louisiana, have been aggressively developed by producers since 2008. Now the nation's leading shale producing area, Haynesville area wells benefit from significant natural gas reserves and impressive initial production rates. CMLP's purchase of the Sabine System in November 2011 added another strategically located asset in a world-class basin. The system is supported by a dedication of approximately 20,000 productive acres under contracts extending until 2021 with experienced shale producers. Due to typically higher relative drilling and development costs of wells in the Haynesville Shale, the decline in natural gas prices has reduced development activity across most of the play. While the backbone of the Sabine System infrastructure has been largely constructed, the system is likely to benefit from infill development drilling by producers when economics improve. In the interim, and to fill available capacity on the system, we have contracted to treat and transport additional third-party natural gas in 2012, providing these customers with access to premium priced markets through our connections to the Gulf South and Tennessee Gas Pipeline systems.



Attributes[1]

Geologic Basin
ArkLaTex

Formation
Haynesville Shale

Area (square miles)
3,600

Estimated Shale Gas Production Through 2011
4.0 Tcf

Approximate 2011 Production
6.0 Bcfd

Technically Recoverable Resource Estimate
72.7 Tcf

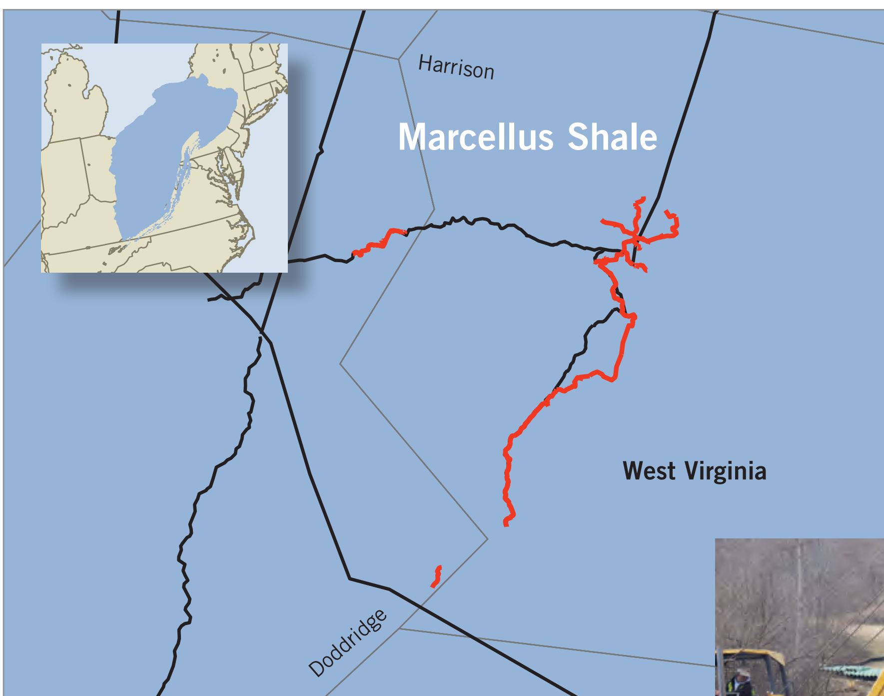
The Sabine System's delivery point to Gulf South Pipeline provides our customers with access to gas markets across the US.

(1) Sources: Energy Information Administration, Bentek Energy and Wood Mackenzie

Marcellus Shale:

Crestwood Marcellus Midstream Joint Venture

The Marcellus Shale, located in West Virginia, Pennsylvania and New York, is considered by many to be the premier North American shale-play due to its aerial extent, resource potential, early phase development cycle and low finding and development costs. While estimates of natural gas reserve potential vary, the industry agrees that the southwestern and northeastern core areas of the Marcellus Shale represent the most productive and economic areas to develop due to impressive initial production rates and high NGL content. Producer development of the Marcellus Shale has been increasing due to the aggressive construction of midstream infrastructure to handle the significant increase in natural gas and NGL volumes. By all accounts, new wells within the core areas of the Marcellus Shale offer significant returns to producers and remain economic to drill even at today's low natural gas prices. The acquisition of the Antero Resources midstream assets, provides CMLP and Crestwood Holdings with an exceptional entry point into the Marcellus Shale. The acquired gathering systems, in Harrison and Doddridge Counties, West Virginia, are located in the southwestern core of the play and are connected to some of the most prolific Marcellus Shale wells completed to date. The 20-year fixed-fee gathering contract with Antero covers approximately 127,000 acres of dedication and provides for minimum production volumes each year until 2019 ensuring acceptable levels of cash flow to Crestwood. Importantly, the Antero acreage dedicated to Crestwood contains substantial rich-gas which improves the production value to Antero and supports consistent development of gas volumes over time. Crestwood's unique joint venture acquisition vehicle allows CMLP to make a meaningful investment in the Marcellus Shale, maintain its conservative capital structure and provides visibility to future CMLP growth through traditional drop down transactions.



Crestwood pipelines

Third-party natural gas and NGL take away pipelines

Attributes[1]

Geologic Basin
Appalachian

Formation
Marcellus Shale

Area (square miles)
10,600

Estimated Shale Gas Production Through 2011
3.1 Tcf

Approximate 2011 Production
2.9 Bcfd

Technically Recoverable Resource Estimate
141.0 Tcf

Construction of gathering pipelines to connect additional wells will be a major initiative for Crestwood Marcellus Midstream during 2012. This crew is boring a road to install a new 16" pipeline in Harrison County, West Virginia.

(1) Sources: Energy Information Administration, Bentek Energy and Wood Mackenzie

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

FORM 10-K

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2011

OR

☐ **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: 001-33631

CRESTWOOD MIDSTREAM PARTNERS LP

(Exact name of registrant as specified in its charter)

Delaware	**56-2639586**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
717 Texas Avenue, Suite 3150, Houston, Texas	**77002**
(Address of principal executive offices)	(Zip Code)

(832) 519-2200
(Registrant's telephone number, including area code)

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

Title of each class	Name of each exchange on which registered
Common Units of Limited Partner Interests	New York Stock Exchange

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

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

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

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 (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ No ☐

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. ☐

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 the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ☐	Accelerated filer ☒
Non-accelerated filer ☐ (Do not check if a smaller reporting company)	Smaller Reporting company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

As of June 30, 2011, the aggregate market value of the registrant's common units held by non-affiliates of the registrant was approximately $532,956,004 based on the closing sale price of $26.95 as reported on the New York Stock Exchange ("NYSE").

As of February 13, 2012, the registrant has 36,538,228 common units outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

None

COMMONLY USED TERMS

As generally used within the energy industry and in this report, unless the context otherwise requires:

"Bbl(s)" means barrel or barrels

"Bbld" means barrel or barrels per day

"Btu" means British Thermal units, a measure of heating value

"hp" means horsepower

"Mcf" means thousand cubic feet

"MMBtu" means million Btu

"MMcf" means million cubic feet

"MMcfd" means million cubic feet per day

"MMcfe" means MMcf of natural gas equivalents, calculated as one Bbl of oil or NGLs equaling six Mcf of gas

"MMcfed" means MMcfe per day

"NGL(s)" means natural gas liquids

"Oil" includes crude oil and condensate

"Tcfe" means trillion cubic feet of natural gas equivalents

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For the Year Ended December 31, 2011

FORWARD-LOOKING INFORMATION

Certain statements contained in this report and other materials we file with the U.S. Securities and Exchange Commission ("SEC"), or in other written or oral statements made or to be made by us, other than statements of historical fact, are "forward-looking statements" as defined in the Private Securities Litigation Reform Act of 1995. Forward-looking statements reflect our current expectations or forecasts of future events. Words such as "may," "assume," "forecast," "predict," "strategy," "expect," "intend," "plan," "aim," "estimate," "anticipate," "believe," "project," "budget," "potential," or "continue," and similar expressions are used to identify forward-looking statements. Forward-looking statements can be affected by assumptions used or by known or unknown risks or uncertainties. Consequently, no forward-looking statements can be guaranteed.

Important factors that could cause our actual results to differ materially from the results contemplated by such forward-looking statements include, but are not limited to, the following risks and uncertainties:

- changes in general economic conditions;
- fluctuations in oil, natural gas and NGL prices;
- the extent and success of drilling efforts, as well as the extent and quality of natural gas volumes produced within proximity of our assets;
- failure or delays by our customers in achieving expected production in their natural gas projects;
- competitive conditions in our industry and their impact on our ability to connect natural gas supplies to our gathering and processing assets or systems;
- actions or inactions taken or non-performance by third parties, including suppliers, contractors, operators, processors, transporters and customers;
- our ability to consummate acquisitions, successfully integrate the acquired businesses, realize any cost savings and other synergies from any acquisition;
- changes in the availability and cost of capital;
- operating hazards, natural disasters, weather-related delays, casualty losses and other matters beyond our control;
- timely receipt of necessary government approvals and permits, our ability to control the costs of construction, including costs of materials, labor and right-of-way and other factors that may impact our ability to complete projects within budget and on schedule;
- the effects of existing and future laws and governmental regulations, including environmental and climate change requirements;
- the effects of existing and future litigation;
- risks related to our substantial indebtedness; and
- certain factors discussed elsewhere in this report.

These factors do not necessarily include all of the important factors that could cause actual results to differ materially from those expressed in any of our forward-looking statements. Other factors could also have material adverse effects on future results. Consequently, all of the forward-looking statements made in this document are qualified by these cautionary statements, and we cannot assure you that actual results or developments that we anticipate will be realized or, even if substantially realized, will have the expected consequences to, or effect on, us or our business or operations. Also note that we provide additional cautionary discussion of risks and uncertainties under the captions "Risk Factors," "Management's Discussion and Analysis of Financial Condition and Results of Operations" and elsewhere in this report.

Although the expectations in the forward-looking statements are based on our current beliefs and expectations, caution should be taken not to place undue reliance on any such forward-looking statements because such statements speak only as of the date hereof. Except as required by federal and state securities laws, we undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise. All forward-looking statements attributable to us or any person acting on our behalf are expressly qualified in their entirety by the cautionary statements contained or referred to in this report and in our future periodic reports filed with the SEC. In light of these risks, uncertainties and assumptions, the forward-looking events discussed in this report may not occur.

PART I

Item 1. Business

General Overview

Crestwood Midstream Partners LP ("CMLP") is a growth-oriented Delaware master limited partnership organized in 2007 to own, operate, acquire and develop midstream energy assets. Our common units are publicly-traded and listed on the NYSE under the symbol "CMLP." Crestwood Gas Services GP LLC, our general partner ("General Partner") is owned by Crestwood Holdings Partners, LLC and its affiliates ("Crestwood Holdings"). We are managed by our General Partner and conduct substantially all of our business through CMLP. First Reserve Management, LP ("First Reserve"), a private equity firm with substantial investments in the energy industry, owns a significant equity interest in Crestwood Holdings. Our principal executive offices are located at 717 Texas Avenue, Suite 3150, Houston, Texas 77002, our telephone number is 832-519-2200 and our website address is www.crestwoodlp.com. Information appearing on our website, or otherwise connected to our website, is not incorporated by reference into this report. In this report, unless the context requires otherwise, references to "we," "us," "our" or the "Partnership" are intended to mean the business and operations of CMLP and its subsidiaries.

On October 1, 2010, Quicksilver Resources Inc. ("Quicksilver") sold all of its ownership interests in CMLP to Crestwood Holdings ("Crestwood Transaction"), the terms of which included:

- Crestwood Holdings' purchase of a 100% interest in our General Partner;
- Crestwood Holdings' purchase of 5,696,752 common units and 11,513,625 subordinated units;
- Crestwood Holdings' purchase of a $58 million subordinated promissory note ("Subordinated Note") payable by CMLP which had a carrying value of approximately $58 million at closing; and
- $701 million in cash paid to Quicksilver and conditional consideration in the form of potential additional cash payments from Crestwood Holdings in 2012 and 2013 of up to $72 million in the aggregate, depending upon achievement of certain defined average volume targets above an agreed threshold for 2011 and 2012, respectively.

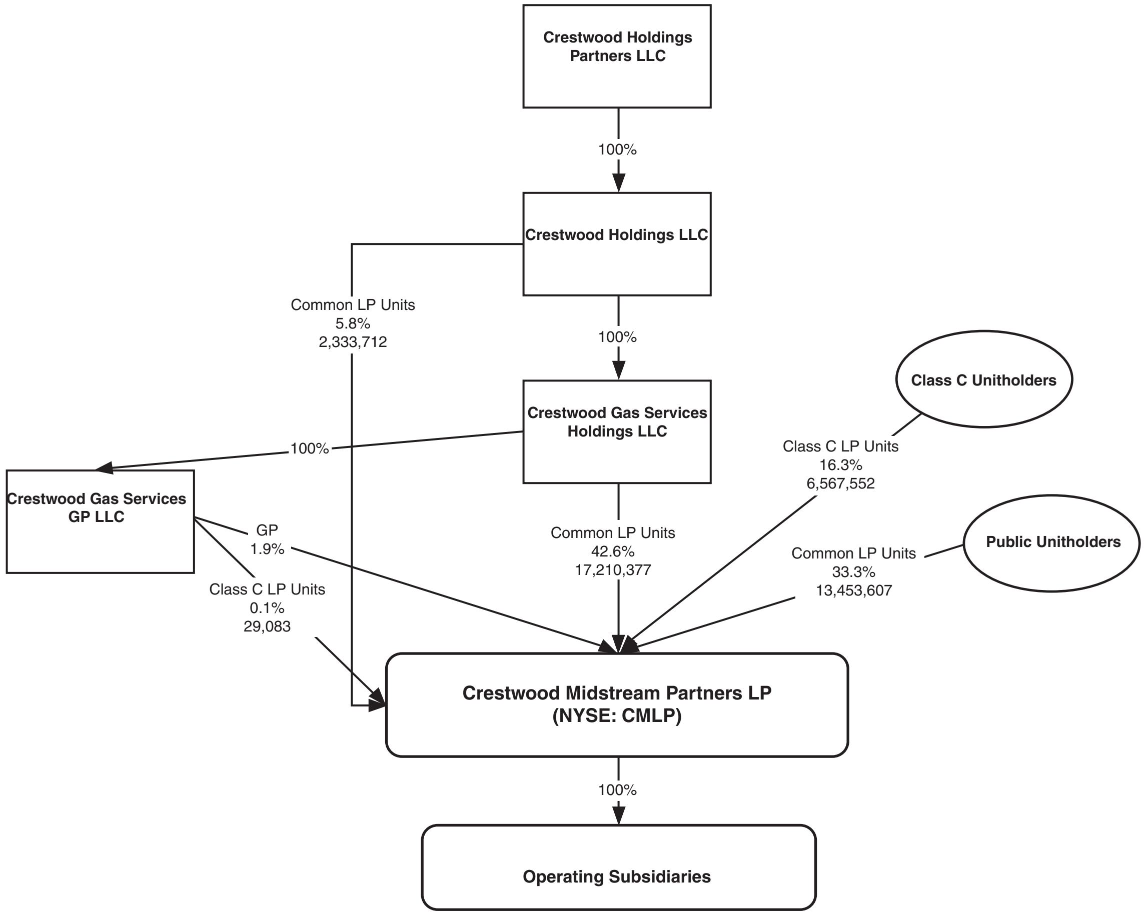
On October 18, 2010, subsequent to the closing of the Crestwood Transaction, the conflicts committee of our General Partner unanimously approved the conversion of our subordinated note payable by CMLP into 2,333,712 common units in exchange for the outstanding balance of the subordinate note. In addition, on November 12, 2010, our subordination period ended resulting in the conversion of 11,513,625 of our subordinated units to common units on a one for one basis.

Name and Ticker Symbol Change. On October 4, 2010, our name changed from Quicksilver Gas Services LP to Crestwood Midstream Partners LP and our ticker symbol on the NYSE for our publicly traded common units changed from "KGS" to "CMLP."

We are primarily engaged in the gathering, processing, treating, compression, transportation and sales of natural gas and the delivery of NGLs produced from the geological formations of the Barnett Shale in north Texas, the Avalon Shale area of southeastern New Mexico, the Fayetteville Shale in northwestern Arkansas, the Granite Wash in the Texas Panhandle and the Haynesville/Bossier Shale in western Louisiana. More than 95% of our gross margin, which we define as total revenue less product purchases, is derived from fee-based service contracts, which minimizes our commodity price exposure and provides us with less volatile operating performance and cash flows.

Organizational Structure

The following chart depicts our ownership structure as of December 31, 2011:



As of December 31, 2011 and February 13, 2012, subsequent to the public offering of 3,500,000 common units, our ownership is as follows:

	December 31, 2011			February 13, 2012		
	Crestwood Holdings	Public	Total	Crestwood Holdings	Public	Total
General partner interest	1.9%	—	1.9%	1.7%	—	1.7%
Limited partner interest:						
Common unitholders	48.4%	33.3%	81.7%	44.4%	38.6%	83.0%
Class C unitholders	0.1%	16.3%	16.4%	0.1%	15.2%	15.3%
Total	50.4%	49.6%	100.0%	46.2%	53.8%	100.0%

Recent Events

Tygart Valley Pipeline

On December 13, 2011, we announced the signing of a Memorandum Of Understanding ("MOU") with Mountaineer Keystone LLC ("MK"), a related party, to construct a 16 inch natural gas gathering system of approximately 42 miles ("Tygart Valley Pipeline or TVP") to serve MK's Marcellus Shale development program in northeast West Virginia.

On February 22, 2012 we entered in to an amendment to the MOU ("MOU Amendment"), which extends the term of the MOU, including its exclusivity provisions, through January 31, 2013 ("Extension Period"). In addition to the Extension Period, the MOU Amendment provides that any requested reimbursement of Tygart Valley Pipeline ("TVP") project costs incurred by us during the Extension Period relating to the TVP project shall be limited to a cumulative total of $2.25 million except as otherwise approved in advance by MK.

Antero Resources Marcellus Shale Gathering Assets Acquisition

On February 24, 2012, we and Crestwood Holdings LLC, through a newly formed joint venture named Crestwood Marcellus Midstream LLC ("Joint Venture"), entered into a purchase agreement, dated as of February 24, 2012 ("Purchase Agreement"), with Antero Resources Appalachian Corporation ("Antero"), pursuant to which the Joint Venture will acquire certain of Antero's Marcellus Shale gathering system assets located in Harrison and Doddridge Counties, West Virginia for $375 million in cash plus an earn-out which would allow Antero to earn additional purchase price payments of up to $40 million based upon average annual production levels achieved during 2012 and 2013 ("Antero Acquisition"). Additionally, at closing, the parties have agreed to enter into a 20-year gas gathering and compression agreement ("GGA"), which will provide for an area of dedication of approximately 127,000 gross acres, or 104,000 net acres ("AOD"), largely located in the rich gas window of the southwestern core of the Marcellus Shale play. The Purchase Agreement contains customary representations and warranties and covenants by each of the parties. The transaction will have a January 1, 2012 effective date and is expected to close in March 2012, subject to regulatory approvals and customary closing conditions.

In conjunction with the formation of the Joint Venture, CMLP and Crestwood Holdings LLC have agreed to enter into a limited liability company agreement and an operating agreement governing the Joint Venture. The structure of the Joint Venture and its governing agreements were reviewed and approved by the Conflicts Committee of the Board of Directors of our General Partner with the advice of separate counsel. Under the terms of the Joint Venture, at closing of the Antero Acquisition, we will contribute approximately $131 million, in exchange for a 35% membership interest in the Joint Venture and Crestwood Holdings LLC is obligated to contribute approximately $244 million in return for a 65% membership interest in the Joint Venture. We expect to utilize available capacity under our Credit Facility to fund our contribution to the Joint Venture.

We will operate the Joint Venture and all costs associated with the operation of the Joint Venture and the Antero assets will be reimbursed to us by the Joint Venture. Concurrent with the formation of the Joint Venture, we and Crestwood Holdings LLC, arranged for a $200 million Joint Venture revolving credit facility to be utilized by the Joint Venture for capital expenditures relating to the installation of gathering systems and compressor stations in the AOD as required by the GGA.

The AOD is largely located within the rich gas window of the southwestern core Marcellus Shale play in northern West Virginia. The Antero assets consist of approximately 33 miles of low pressure gathering system currently gathering approximately 210 MMcfd of natural gas produced from 59 existing Antero horizontal Marcellus Shale wells located within the AOD. The gathering pipelines deliver Antero's Marcellus Shale production to various regional pipeline systems including Columbia, Dominion, and Equitrans and later this year will begin deliveries to intermediate systems which will connect to Mark West Energy Partners' Sherwood Gas

Processing Plant, expected to be placed in service in the third quarter of 2012. The GGA provides the Joint Venture with a right of first offer, for seven years from closing, to acquire any future Antero midstream assets sold by Antero in an area of approximately 100,000 acres adjacent to the AOD that includes prospective rich gas acreage. Under the GGA, Antero will pay the Joint Venture a fixed fee per Mcf (subject to annual escalations) for all low pressure gathering, high pressure gathering and compression services requested by Antero in the AOD. Additionally, Antero will provide an annual minimum volume throughput commitment, at applicable contract fees, commencing with 300 MMcfd in 2012 and increasing to 450 MMcfd in 2018. This minimum volume commitment feature will provide the Joint Venture with a minimum threshold of cash flow applicable to the Antero assets each year, based upon actual volumes compared to contractual minimum volume commitments for such year.

Subsequent Equity Offering

On January 13, 2012, we completed a public offering of 3,500,000 common units representing limited partner interests in us at a price of $30.73 per common unit ($29.50 per common unit, net of underwriting discounts), providing net proceeds of approximately $102.8 million. We used the net proceeds from the offering to reduce indebtedness under our senior secured credit facility, as amended, dated effective October 1, 2010 ("Credit Facility"). In connection with the issuance of the common units, our General Partner did not make an additional capital contribution resulting in a reduction in our General Partner's general partner interest in us to approximately 1.74%.

Business Strategy

Our business strategy is to capitalize on our competitive strengths to increase our revenue, profitability and cash flow by:

Pursuing growth through midstream acquisitions and greenfield projects. We are a growth-oriented master limited partnership focused on acquiring natural gas gathering, processing, treating, compression and transportation assets in shale plays. We believe that our experience and market position will allow us to realize significant ongoing growth opportunities by selectively acquiring additional assets at attractive prices. Our acquisition strategy includes diversifying and extending our geographic, customer and business profile and providing visible organic growth opportunities. This strategy was illustrated by our acquisitions of approximately $423 million of midstream assets and businesses in 2011. We expect our acquisition strategy to evolve over time and to focus on a balance of growth opportunities in both dry gas and rich gas shale plays. We will also focus on expanding through the acquisition of competitor systems and plants in the areas we operate.

Increasing utilization of existing assets and expanding our pipeline system capacities to meet our customers' needs and to attract new customers. Our producers drilling programs have resulted in and, we believe, will continue to result in increased volumes through our systems. For example, our gathering volumes in the Barnett Shale increased 38% year-over-year in 2011. We believe that the location of our existing assets and relationships with active producers position us well to capture the growing need for midstream services. We aim to attract increased gathering, processing and treating volumes by marketing our midstream services, expanding our gathering systems and providing superior customer service to natural gas producers. We will compete for new customers based on available capacity in our systems, competitive fees for service and our willingness to construct expanded facilities.

Maintaining a disciplined financial policy and financing flexibility. We have significantly grown our midstream business while maintaining a disciplined financial policy. We believe in operating with a reasonable amount of leverage as we have to date, and we expect to continue this strategy by balancing the amount of leverage with our growth objectives, cash flow and equity. Our growth strategy is also based upon our ability to access various sources of capital. We have a supportive relationship with a diverse group of domestic and international banks, which have committed an aggregate of $500 million under our Credit Facility, which matures on October 1, 2015. We believe the available borrowing capacity under our Credit Facility, combined with cash flow from operations and our proven ability to access the capital markets will enable us to achieve our growth strategy.

Our Strengths

We believe that we are well positioned to successfully execute our primary business strategies due to the following competitive strengths:

Our assets are located in attractive shale plays. Our assets are located in both dry gas and rich gas shale plays which are marked by favorable characteristics such as proven production, substantial gas in-place, improving development and operating costs and existing intrastate and interstate pipeline infrastructure. We believe that our established positions in these areas, together with anticipated growth in production from our producers, give us an opportunity to expand our gathering system footprint and increase our throughput volumes and plant utilization, ultimately increasing cash flows.

A history of improving well performance and lower operating and development costs associated with our areas of operation generally enable producers to achieve attractive returns on investment through various gas price environments. In addition, certain of our assets gather and process natural gas in rich gas shale plays which typically contain NGLs that currently receive favorable pricing. The NGLs create additional value and improved drilling economics for our producers. We have two systems located in basins that include NGL rich gas shale plays, (i) the Cowtown System, part of the Barnett segment and, (ii) the Granite Wash System. In 2011, our systems located in NGL rich basins or rich gas shale plays contributed approximately 53% of our total revenue. Additionally, existing intrastate and interstate pipelines interconnect with our midstream assets to provide our customers with access to growing and diverse natural gas markets, located in the Northeast, Midwest and Southeastern United States. These factors support continued producer drilling and development activity in the basins or shale plays in which we operate.

Our customer contracts are typically long-term and fixed fee. Our primarily fixed-fee and long-term contract structure largely eliminates our exposure to direct commodity price risk and provides us with long-term cash flow stability. More than 95% of our gross margin, which we define as total revenue less product purchases, is derived from fee-based service contracts. The initial terms of a substantial number of our contracts extend through 2020. In addition, current and planned production from acreage dedications from Quicksilver, BHP Billiton Petroleum (“BHP”), British Petroleum, Plc. (“BP”), Exxon Mobil Corporation (“ExxonMobil”) and Chesapeake Energy Corporation (“Chesapeake”) should provide future growth.

We own and operate high quality, integrated assets. Substantially all of our assets have been constructed since 2006, which enables us to provide efficient and reliable service to our producers. Our relatively new asset base in relation to our competitors benefits from both low operating costs and minimal capital requirements. The integrated nature of our operations by which we provide gathering, processing, treating, compression, transportation and sales services, positions us well to serve our customers. Our system infrastructure and capacities have been designed to accommodate long-term basin development plans.

We have an experienced, knowledgeable management team with a proven record of performance. Our senior management team has substantial experience in the oil and gas industry with a proven record of enhancing value through the acquisition, integration, development and operation of midstream companies and publicly-traded entities. We believe that this team provides us with a strong foundation for developing additional natural gas gathering and processing assets and pursuing strategic acquisition opportunities.

We have strong sponsor support. First Reserve owns a significant equity interest in Crestwood Holdings, and as a result, has significant control over our operations. First Reserve has shown a strong commitment to our success to date, and we believe that they will continue to support our ongoing development. We believe that First Reserve is one of the most respected and seasoned private equity investors focusing on the energy sector.

Acquisitions

We have completed the following acquisitions during 2011:

Las Animas Acquisition

On February 16, 2011, we completed the acquisition of certain midstream assets in the Avalon Shale play from a group of independent producers for $5.1 million (“Las Animas Acquisition”).

At the time of the acquisition, the Las Animas assets consisted of approximately 46 miles of natural gas gathering pipeline located in the Morrow/Atoka trend and the emerging Avalon Shale trend in southeastern New Mexico (“Las Animas System”). The pipelines are supported by long-term, fixed-fee contracts which include existing Morrow/Atoka production and dedications of approximately 55,000 acres. The Avalon Shale is a NGL rich oil and gas field that is part of the Permian Basin.

Frontier Gas Acquisition

On April 1, 2011, we completed the acquisition of certain midstream assets in the Fayetteville Shale and the Granite Wash from Frontier Gas Services, LLC for approximately $345 million (“Frontier Gas Acquisition”).

Fayetteville

At the time of the acquisition, the Fayetteville assets consisted of approximately 130 miles of high pressure and low pressure gathering pipelines in northwestern Arkansas with capacity of approximately 510 MMcfd, treating capacity of approximately 165 MMcfd and approximately 35,000 hp of compression (“Fayetteville System”). The Fayetteville System interconnects with multiple interstate pipelines which serve the Fayetteville Shale and are supported by long-term, fixed-fee contracts with producers who dedicated approximately 100,000 acres in the core of the Fayetteville Shale to us. These contracts have initial terms that extend through 2020 and include an option, for either party to the contract, to extend through 2025.

Granite Wash

At the time of the acquisition, the Granite Wash assets consisted of a 28 mile pipeline system and a 36 MMcfd cryogenic processing plant in the Texas Panhandle (“Granite Wash System”). The Granite Wash System is supported by more than 13,000 dedicated acres and long-term contracts with initial terms that extend through 2022. The Granite Wash System has emerged as a NGL rich natural gas play with active drilling programs by various producers.

Tristate Acquisition

On November 1, 2011, we acquired Tristate Sabine, LLC (“Tristate”) from affiliates of Energy Spectrum Capital, Zwolle Pipeline, LLC and Tristate’s management for approximately $73 million in cash consideration comprised of $65 million paid at closing plus a deferred payment of $8 million one year following the closing date, subject to customary post-closing adjustments (“Tristate Acquisition”).

At the time of the acquisition, the Tristate assets located in Haynesville/Bossier Shale consisted of approximately 60 miles of high pressure and low pressure gathering pipelines in western Louisiana with capacity of approximately 100 MMcfd, and treating capacity of approximately 80 MMcfd (“Sabine System”). The Sabine System is supported by long-term, fixed-fee contracts with producers who dedicated approximately 20,000 acres to us. These contracts have various initial terms that extend through 2019 to 2021.

Our Operating Segments

We conduct all of our operations in the midstream sector with three reportable operating segments. These operating segments reflect how we manage our operations and reflect the primary geographic areas in which we operate. The operating segments consist of Barnett, Fayetteville and Granite Wash. All of our operating segments are engaged in gathering, processing, treating, compression, transportation and sales of natural gas in the United States. See Part II, Item 8, “Financial Statements and Supplementary Data — Note 20 — Segment Information.”

As of December 31, 2011, we managed approximately 723 miles of natural gas gathering pipelines, NGL, gas lift, residue and production lines of which we own approximately 566 that range in size from four to twenty inches in diameter.

Barnett:

Cowtown System. Located principally in Hood and Somervell Counties, Texas in the southern portion of the Fort Worth Basin, the Cowtown System includes:

- the Cowtown pipeline, which consists of a rich gas gathering system and related gas compression facilities, that gathers natural gas produced by our customers and delivers it to the Cowtown or Corvette plants for processing;
- the Cowtown plant, which consists of two natural gas processing units that extract NGLs from the natural gas stream and deliver customers’ residue gas and extracted NGLs to unaffiliated pipelines for sale downstream; and
- the Corvette plant, which extracts NGLs from the natural gas stream and delivers customers’ residue gas and extracted NGLs to unaffiliated pipelines for sale downstream.

Residue gas from Cowtown may be delivered to Atmos Energy Corporation, Enterprise Texas Pipeline LLC and/or Energy Transfer Partners, LP (“Energy Transfer”). Residue gas from the Corvette plant is delivered to Energy Transfer. Extracted NGLs from the Cowtown and Corvette plants are delivered to West Texas Pipeline, LP and Lone Star NGL LLC for delivery to Mont Belvieu, Texas. For the year ended December 31, 2011, the Cowtown and Corvette plants had a total average throughput of 132 MMcfd of natural gas, resulting in average NGL recovery of 16,567 Bbld.

Lake Arlington System. Located in eastern Tarrant County, Texas, the Lake Arlington System consists of a dry gas gathering system and related gas compression facility. This system gathers natural gas produced by our customers and delivers it to Energy Transfer Partners.

Alliance System. Located in northern Tarrant and southern Denton Counties, Texas, the Alliance System consists of a dry gas gathering system with a related dehydration, compression and an amine treating facility. This system gathers natural gas produced by our customers and delivers it to Energy Transfer and Crosstex Partners, LP (“Crosstex”).

Fayetteville:

Twin Groves / Prairie Creek / Woolly Hollow Systems. Located in Conway and Faulkner Counties, Arkansas, the Twin Groves/Prairie Creek/Woolly Hollow Systems consist of three dry gas gathering, compression, dehydration and treating facilities. These systems gather natural gas produced by BHP, BP, and ExxonMobil and interconnects with Ozark Gas Transmission, Boardwalk Gas Transmission and Fayetteville Express pipelines.

Rose Bud System. Located in White County, Arkansas, the Rose Bud System consists of a dry gas gathering system and a related compression facility. This system gathers natural gas produced by ExxonMobil and interconnects with Ozark Gas Transmission.

Wilson Creek System. Located in Van Buren County, Arkansas, the Wilson Creek System consists of a dry gas gathering system and a related compression facility. This system gathers natural gas produced by independent producers and interconnects with Ozark Gas Transmission.

Granite Wash:

Granite Wash System. Located in Roberts County, Texas, the Granite Wash System consists of:

- the Indian Creek rich gas gathering system and related compression facility; and
- the Indian Creek plant, which consists of a gas processing unit that extracts NGLs from the gas stream.

The residue gas and extracted NGLs are delivered to unaffiliated downstream pipelines for sale. This system gathers rich natural gas produced by Chesapeake, Linn Energy, LLC and Great Plains Operating, LLC and interconnects with Mid-America Pipeline, a subsidiary of Enterprise Products Partners, L.P. ("Enterprise Products") for ultimate delivery of NGLs to either Conway or Mont Belvieu, which historically has received premium pricing compared to the Conway NGL market. Additionally, residue gas interconnects with ANR Pipeline and Northern Natural Gas Pipeline to provide access to the Mid-Continent gas markets.

Other:

Las Animas System. Located in Eddy County, New Mexico, the Las Animas System consists of three dry gas gathering systems in the existing Morrow/Atoka trend which are located near the emerging Avalon Shale rich gas trend. The Las Animas System includes dedication of acreage from Bass Oil Production Company through 2017. We expect that producers in the area will target the Avalon Shale with drilling programs and as this occurs, we believe our assets will be well positioned to benefit from future drilling in the NGL rich Avalon Shale formation.

Sabine System. Located in Sabine Parish, Louisiana, the Sabine System consists of approximately 60 miles of high-pressure dry gas gathering pipelines. The system provides gathering and treating services for production from Chesapeake, Comstock Resources, Inc., Forest Oil Corporation, Wildcat Sabine Pipeline LLC and Devon Energy Corporation ("Devon") in the Haynesville/Bossier Shale and interconnects with Gulf South Pipeline and Tennessee Gas Pipeline.

All of our pipelines are constructed on rights-of-way granted by the owners of the property. We have obtained, where necessary, license or permit agreements from public authorities and railroad companies to cross over or under, or to lay facilities in or along, waterways, roads, railroad properties and state highways, as applicable. In some cases, property on which our pipelines were built was purchased in fee.

We believe that, subject to any encumbrances, we have satisfactory title to our assets. We do not believe that any of these encumbrances will materially reduce the value of our properties or our interest in these properties or interfere with their use in the operation of our business. The following table lists our properties and approximate asset capabilities as of December 31, 2011 by location:

	Pipeline Miles	Nominal Capacities (MMcfd)				Installed Compression (Hp)	Compression Units
		Gathering	Processing	Treating	Dehydration		
Barnett							
Owned							
Cowtown System	218	325	325	—	325	80,490	20
Lake Arlington System	10	230	—	—	235	30,480	7
Alliance System	39	300	—	340	240	48,720	10
Barnett - Owned	**267**	**855**	**325**	**340**	**800**	**159,690**	**37**
Operated non-owned							
Cowtown System	112	—	—	—	—	—	—
Lake Arlington System	10	—	—	—	—	—	—
Alliance System	35	—	—	—	—	—	—
Barnett - Operated	**157**	**—**	**—**	**—**	**—**	**—**	**—**
Total Barnett - Owned/Operated	**424**	**855**	**325**	**340**	**800**	**159,690**	**37**
Fayetteville							
Twin Groves/Prairie Creek/Woolly Hollow System	122	350	—	165	—	32,470	18
Wilson Creek System	24	100	—	—	—	630	1
Rosebud System	15	60	—	—	—	630	1
Total Fayetteville	**161**	**510**	**—**	**165**	**—**	**33,730**	**20**
Granite Wash							
Granite Wash System	**31**	**36**	**36**	**—**	**—**	**9,170**	**9**
Other							
Las Animas System	47	50	—	—	34	—	1
Sabine System	60	100	—	74	72	—	—
Total Other	**107**	**150**	**—**	**74**	**106**	**—**	**1**
Total	**723**	**1,551**	**361**	**579**	**906**	**202,590**	**67**

Competition

The midstream natural gas industry is highly competitive. Competition is based on, among other things, the following:

- reputation;
- efficiency;
- flexibility;
- size;
- credit quality; and reliability of the gatherer;

- the pricing arrangements offered by the gatherer;
- location of the gatherer's pipeline facilities; and
- the gatherer's ability to offer a full range of services including natural gas gathering, processing, treating, compression, transportation and sales.

We believe that offering an integrated package of services allows us to compete more effectively for new natural gas supplies in our operating areas.

We face strong competition in acquiring new natural gas supplies and in pursuing acquisition opportunities as part of our long-term growth strategy. Our competitors include entities that gather, process and market natural gas. Our competitors may have capital resources and control supplies of natural gas greater than ours. Competition is typically impacted by the level of drilling activity in a particular geographic region, as well as fluctuations in commodity prices for oil, natural gas and NGLs.

Our primary competitors in the midstream industry consist of Energy Transfer, Crosstex, Eagle Rock Energy Partners, LP, Enterprise Products and certain producer-owned gathering systems.

We believe that we are able to compete with these companies based on gathering and processing efficiencies, operating costs and commercial terms offered to producers, along with the location and available capacity of our gathering systems and processing plants.

Customers and Concentration of Credit Risk

Quicksilver was the only customer from whom revenues exceeded 10% of our consolidated revenues for the years ended December 31, 2011, 2010 and 2009.

During 2011, Quicksilver accounted for 64% of our total consolidated revenue, including approximately 7% that is comprised of natural gas purchased by Quicksilver from Eni SpA and gathered under Quicksilver's Alliance System gathering agreement. Quicksilver accounted for 93% and 95% of our total consolidated revenues for the years ended December 31, 2010 and 2009, respectively.

Although Quicksilver continues to develop its resources in counties in and around the Barnett Shale, reductions in its future drilling programs could result in reduced volumes gathered, treated and processed in our facilities, if not replaced by other producers in the affected system or other system. In addition, a default in Quicksilver's payments to us for our services could have a material impact on our cash flows.

Governmental Regulation

Regulation of our business may affect certain aspects of our operations and the market for our products and services. State regulation of gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory requirements, complaint-based rate regulation or general utility regulation. In Texas, we have filed tariffs with the Texas Railroad Commission ("TRRC") to establish rates and terms of service for certain of our lines.

In Texas, our assets also include intrastate common carrier NGL pipelines subject to the regulation of the TRRC, which requires that our NGL pipelines file tariff publications that contain all the rules and regulations governing the rates and charges for services we perform. NGL pipeline rates may be limited to provide no more than a fair return on the aggregate value of the pipeline property used to render services.

Gathering pipeline regulation

Section 1(b) of the Natural Gas Act, or "NGA", exempts natural gas gathering facilities from the jurisdiction of the Federal Energy Regulatory Commission ("FERC"). Our natural gas gathering activity is not subject to Internet posting requirements imposed by FERC as a result of FERC's market transparency initiatives. We believe that our natural gas pipelines meet the traditional tests that FERC has used to determine that a pipeline is a gathering pipeline and is, therefore, not subject to FERC jurisdiction. The distinction between FERC-regulated transmission services and federally unregulated gathering services, however, is the subject of substantial, on-going litigation, so the classification and regulation of our gathering facilities are subject to change based on future determinations by FERC, the courts or Congress. State regulation of gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements and complaint-based rate regulation. In recent years, FERC has taken a more light-handed approach to regulation of the gathering activities of interstate pipeline transmission companies, which has resulted in a number of such companies transferring gathering facilities to unregulated affiliates. As a result of these activities, natural gas gathering may begin to receive greater regulatory scrutiny at both the state and federal levels. Our natural gas gathering operations could be adversely affected should they be subject to more stringent application of state or federal regulation of rates and services. Our natural gas gathering operations also may be or become subject to additional safety and operational regulations relating to the design, installation, testing, construction, operation, replacement and management of gathering facilities. Additional rules and legislation pertaining to these matters are considered or adopted from time to time. We cannot predict what effect, if any, such changes might have on our operations, but the industry could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes.

Our natural gas gathering operations are subject to ratable take and common purchaser statutes. These statutes generally require our gathering pipelines to take natural gas without undue discrimination as to source of supply or producer. These statutes are designed to prohibit discrimination in favor of one producer over another producer or one source of supply over another source of supply. The regulations under these statutes can have the effect of imposing some restrictions on our ability as an owner of gathering facilities to decide with whom we contract to gather natural gas. The states in which we currently operate have adopted complaint-based regulation of natural gas gathering activities, which allows natural gas producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to gathering access and rate discrimination. We cannot predict whether such a complaint will be filed against us in the future. Failure to comply with state regulations can result in the imposition of administrative, civil and criminal remedies. To date, there has been no adverse effect to our systems due to these regulations.

Safety and Maintenance Regulation

The pipelines we use to gather and transport natural gas and NGLs are subject to regulation by the Pipeline and Hazardous Materials Safety Administration ("PHMSA") of the Department of Transportation ("DOT"), pursuant to the Natural Gas Pipeline Safety Act of 1968, as amended ("NGPSA") with respect to natural gas and Hazardous Liquids Pipeline Safety Act of 1979, as amended, or the ("HLPSA") with respect to NGLs. Both the NGPSA and the HLPSA have been amended by the Pipeline Safety Improvement Act of 2002 ("PSIA") which was reauthorized and amended most recently by the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011. The NGPSA regulates safety requirements in the design, construction, operation and maintenance of natural gas and NGL pipeline facilities, while the PSIA establishes mandatory inspections for all U.S. liquid and gas transportation pipelines and some gathering lines in high-population areas.

The PHMSA has developed regulations implementing the PSIA that require transportation pipeline operators to implement integrity management programs, including more frequent inspections and other measures to ensure pipeline safety in "high consequence areas," such as high population areas, areas unusually sensitive to environmental damage and commercially navigable waterways. We, or the entities in which we own an interest, inspect our pipelines regularly in compliance with state and federal maintenance requirements.

States are largely preempted by federal law from regulating pipeline safety for interstate lines but most are certified by the DOT to assume responsibility for enforcing federal intrastate pipeline regulations and inspection of intrastate pipelines. In practice, because states can adopt stricter standards for intrastate pipelines than those imposed by the federal government for interstate lines, states vary considerably in their authority and capacity to address pipeline safety. We do not anticipate any significant difficulty in complying with applicable state laws and regulations. Our pipelines have operations and maintenance plans designed to keep the facilities in compliance with pipeline safety requirements.

In addition, we are subject to a number of federal and state laws and regulations, including the Occupational Safety and Health Administration ("OSHA") and comparable state statutes, the purposes of which are to protect the health and safety of workers, both generally and within the pipeline industry. In addition, the OSHA hazard communication standard, the Environmental Protection Agency's ("EPA") community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act and comparable state statutes require that information be maintained concerning hazardous materials used or produced in our operations and that such information be provided to employees, state and local government authorities and citizens.

We and the entities in which we own an interest are also subject to OSHA Process Safety Management regulations, as well as the EPA's Risk Management Program ("RMP") which are designed to prevent or minimize the consequences of catastrophic releases of toxic, reactive, flammable or explosive chemicals. These regulations apply to any process which involves a chemical at or above specified thresholds or any process which involves flammable liquid or gas in excess of 10,000 pounds. We have an internal program of inspection designed to monitor and enforce compliance with worker safety requirements. We believe that we are in material compliance with all applicable laws and regulations relating to worker health and safety.

Environmental Matters

General

Our operation of pipelines, plants and other facilities to provide midstream services is subject to stringent and complex federal, state and local laws and regulations relating to the protection of the environment. As an owner or operator of these facilities, we must comply with these laws and regulations at the federal, state and local levels. These laws and regulations can restrict or impact our business activities in many ways, such as the following:

- requiring the acquisition of various permits to conduct regulated activities;
- requiring the installation of pollution-control equipment or otherwise restricting the way we can handle or dispose of our wastes;
- limiting or prohibiting construction activities in sensitive areas, such as wetlands, coastal regions or areas inhabited by endangered or threatened species;
- requiring investigative and remedial actions to mitigate or eliminate pollution conditions caused by our operations or attributable to former operations; and
- enjoining the operations of facilities deemed to be in non-compliance with such environmental laws and regulations and permits issued pursuant thereto.

Failure to comply with these laws and regulations may trigger a variety of administrative, civil and criminal enforcement measures, including the assessment of monetary penalties, the imposition of investigatory and remedial obligations and the issuance of orders enjoining future operations or imposing additional compliance requirements. Certain environmental statutes impose strict, and in some cases, joint and several liability for costs required to clean up and restore sites where hazardous substances, hydrocarbons or wastes have been disposed or otherwise released; thus, we may be subject to environmental liability at our currently owned or operated facilities for conditions caused prior to our involvement.

The trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment, and thus, there can be no assurance as to the amount or timing of future expenditures for environmental compliance or remediation and actual future expenditures may be different from the amounts we currently anticipate. We try to anticipate future regulatory requirements that might be imposed and plan accordingly to remain in compliance with changing environmental laws and regulations and to minimize the costs of such compliance. We also actively participate in industry groups that help formulate recommendations for addressing existing or future regulations.

We do not believe that compliance with current federal, state or local environmental laws and regulations will have a material adverse effect on our business, financial condition, results of operations or cash flows. In addition, we believe that the various environmental activities in which we are presently engaged are not expected to materially interrupt or diminish our operational ability to gather, process, compress, treat and transport natural gas and NGLs. We can make no assurances, however, that future events, such as changes in existing laws or enforcement policies, the promulgation of new laws or regulations or the development or discovery of new facts or conditions will not cause us to incur significant costs. Below is a discussion of several of the material environmental laws and regulations that relate to our business. We believe that we are in material compliance with applicable environmental laws and regulations.

Hazardous substances and waste

Our operations are subject to environmental laws and regulations relating to the management and release of hazardous substances, solid and hazardous wastes and petroleum hydrocarbons. These laws generally regulate the generation, storage, treatment, transportation and disposal of solid and hazardous waste and may impose strict, and in some cases, joint and several liability for the investigation and remediation of affected areas where hazardous substances may have been released or disposed. For instance, the Comprehensive Environmental Response, Compensation, and Liability Act (“CERCLA” or “Superfund law”) and comparable state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons referred to as potentially responsible parties (“PRPs”). These PRPs include current owners or operators of the site where a release of hazardous substances occurred, prior owners or operators that owned or operated the site at the time of the release, and companies that disposed or arranged for the disposal of the hazardous substances found at the site. Under CERCLA, PRPs may be subject to strict and joint and several 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. CERCLA also authorizes the EPA and, in some instances, third parties to act in response to threats to the public health or the environment and to seek to recover the costs they incur from the PRPs. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances or other pollutants released into the environment. Despite the “petroleum exclusion” of CERCLA Section 101(14), which currently encompasses natural gas, we may nonetheless handle hazardous substances within the meaning of CERCLA, or similar state statutes, in the course of our ordinary operations and, as a result, may be jointly and severally liable under CERCLA, or similar state statutes, for all or part of the costs required to clean up sites at which these hazardous substances have been released into the environment.

We also generate solid wastes, including hazardous wastes, which are subject to the requirements of the Resource Conservation and Recovery Act (“RCRA”) and comparable state statutes. While RCRA regulates both solid and hazardous wastes, it imposes strict requirements on the generation, storage, treatment, transportation and disposal of hazardous wastes. Certain petroleum production wastes are excluded from RCRA’s hazardous waste regulations. However, it is possible that these wastes, which could include wastes currently generated during our operations, will in the future be designated as “hazardous wastes” and, therefore, be subject to more rigorous and costly disposal requirements. Any such changes in the laws and regulations could have a material adverse effect on our capital expenditures and operating expenses.

We own or lease properties where hydrocarbons are being or have been handled. We have generally utilized operating and disposal practices that were standard in the industry at the time, although hydrocarbons or other wastes may have been disposed of or released on or under the properties owned or leased by us, or on or under the other locations where these hydrocarbons and wastes have been transported for treatment or disposal. In addition, certain of these properties have been operated by third parties whose treatment and disposal or release of hydrocarbons and other wastes was not under our control. These properties and the wastes disposed thereon may be subject to CERCLA, RCRA and analogous state laws. Under these laws, we could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators), to clean up contaminated property (including contaminated groundwater) or to perform remedial operations to prevent future contamination. We are not currently aware of any facts, events or conditions relating to such requirements that could materially impact our financial condition, results of operations or cash flows.

Air emissions

Our operations are subject to the Federal Clean Air Act ("CAA"), and comparable state laws and regulations. These laws and regulations regulate emissions of air pollutants from various industrial sources, including our compressor stations, and also impose various monitoring and reporting requirements. Such laws and regulations may require that we obtain pre-approval for the construction or modification of certain projects or facilities, obtain and strictly comply with air permits containing various emissions and operational limitations and utilize specific emission control technologies to limit emissions. Our failure to comply with these requirements could subject us to monetary penalties, injunctions, conditions or restrictions on operations and, potentially, criminal enforcement actions. We believe that we are in material compliance with these requirements. We may be required to incur certain capital expenditures in the future for air pollution control equipment in connection with obtaining and maintaining permits and approvals for air emissions. We believe, however, that our operations will not be materially adversely affected by such requirements, and the requirements are not expected to be any more burdensome to us than to any other similarly situated companies.

Climate change

In response to findings that emissions of carbon dioxide, methane, and other greenhouse gases ("GHG") present an endangerment to public health and the environment because emissions of such naturally occurring gases are contributing to the warming of the earth's atmosphere and other climate changes, the EPA has adopted regulations under existing provisions of the federal Clean Air Act that would require a reduction in emissions of GHG from motor vehicles and also may trigger construction and operating permit review for GHG emissions from certain stationary sources. The EPA has published its final rule to address the permitting of GHG emissions from stationary sources under the Prevention of Significant Deterioration ("PSD") and Title V permitting programs, pursuant to which these permitting programs have been "tailored" to apply to certain stationary sources of GHG emissions in a multi-step process, with the largest sources first subject to permitting. It is widely expected that facilities required to obtain PSD permits for their GHG emissions also will be required to reduce those emissions according to "best available control technology" standards for GHG that have yet to be developed. These EPA rulemakings could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified facilities. With regard to the monitoring and reporting of GHG, on November 30, 2010, the EPA published a final rule expanding its existing GHG emissions reporting rule published in October 2009 to include onshore and offshore oil and natural gas production and onshore oil and natural gas processing, transmission, storage, and distribution activities, which may include certain of our operations, and to require the reporting of GHG emissions from covered facilities on an annual basis beginning in 2012 for GHG emissions occurring in 2011.

Water discharges

The Federal Water Pollution Control Act ("Clean Water Act") and analogous state laws impose restrictions and strict controls regarding the discharge of pollutants or dredged and fill material into state waters as well as waters of the U.S. and adjacent wetlands. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of permits issued by the EPA, the Army Corps of Engineers or an analogous state agency. Spill prevention, control and countermeasure requirements of federal laws require appropriate containment berms and similar structures to help prevent the contamination of regulated waters in the event of a hydrocarbon spill, rupture or leak. In addition, the Clean Water Act and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities. These permits may require us to monitor and sample the storm water runoff from certain of our facilities. Some states also maintain groundwater protection programs that require permits for discharges or operations that may impact groundwater conditions. We believe that we are in material compliance with these requirements. However, federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations. We believe that compliance with existing permits and compliance with foreseeable new permit requirements will not have a material adverse effect on our financial condition, results of operations or cash flows.

Endangered species

The Endangered Species Act ("ESA") restricts activities that may affect endangered or threatened species or their habitats. While some of our pipelines may be located in areas that are designated as habitats for endangered or threatened species, we believe that we are in material compliance with the ESA. However, the designation of previously unidentified endangered or threatened species could cause us to incur additional costs or become subject to operating restrictions or bans in the affected states.

Anti-terrorism measures

The Department of Homeland Security Appropriation Act of 2007 requires the Department of Homeland Security ("DHS") to issue regulations establishing risk-based performance standards for the security of chemical and industrial facilities, including oil and gas facilities that are deemed to present "high levels of security risk." The DHS issued an interim final rule in April 2007 regarding risk-based performance standards to be attained pursuant to this act and, on establish chemicals of interest and their respective threshold quantities that will trigger compliance. We have determined the extent to which our facilities are subject to the rule, made the necessary notifications and determined that the requirements will not have a material impact on our financial condition, results of operations or cash flows.

Employees

Neither CMLP nor our General Partner has any employees. Employees of Crestwood Holdings provide services to our General Partner pursuant to an Omnibus Agreement, dated October 8, 2010, among our General Partner and Crestwood Holdings ("Omnibus Agreement"). The Omnibus Agreement terminates on the earlier of August 10, 2017 or at such time as Crestwood Holdings ceases to own or control a majority of the issued and outstanding voting securities of our General Partner.

Available Information and Corporate Governance Documents

Available Information

We file our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and all amendments to such reports, as well as other documents electronically with the SEC under the Securities Exchange Act of 1934, as amended ("Exchange Act"). From time-to-time, we may also file registration and related statements pertaining to equity or debt offerings. We provide access free of charge to all of these materials, as soon as reasonably practicable after such materials are filed with, or furnished to the SEC, on our Internet site located at *www.crestwoodlp.com*. The public may also read and copy any materials that we file with the SEC at the SEC's Public Reference Room at 100 F Street, N.E., Room 1580, Washington, DC 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. The public may also obtain such reports from the SEC's Internet website at *www.sec.gov*.

Corporate Governance Documents

Our Corporate Governance Guidelines, Code of Business Conduct and Ethics and the charters of the audit committee and the conflicts committee of our General Partner's board of directors are also available on our Internet website. We will also provide, free of charge, a copy of any of our governance documents listed above upon written request to our General Partner's corporate secretary at our principal executive office. Our principal executive offices are located at 717 Texas Avenue, Suite 3150, Houston, Texas 77002. Our telephone number is 832-519-2200.

Item 1A. Risk Factors

You should carefully consider the following risk factors together, with all of the other information included in this report, when deciding whether to invest in us. Limited partner interests are inherently different from 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 similar business. You should be aware that the occurrence of any of the events described in this report could have a material adverse effect on our business, financial condition, results of operations and cash flows. In such event, we may be unable to make distributions to our unitholders and the trading price of our common units could decline.

Risks Related to Our Business

We are dependent on a limited number of natural gas producers, including Quicksilver, for the natural gas we gather, process, treat, compress, transport and sell. A material reduction in production by these customers would result in a material decline in our revenue and cash available for distribution.

We rely on a limited number of customers for our revenue. Our top five customers comprised approximately 92% of our total consolidated revenues in 2011. Although many of our contracts extend to 2020 and beyond, we may be unable to negotiate on favorable terms, if at all, any extension or replacement of our contracts with such customers after the term of their respective contracts expire. Our largest customer, Quicksilver, accounted for 64% of our total consolidated revenues in 2011, including approximately 7% that was comprised of natural gas purchased by Quicksilver from Eni SpA and gathered under Quicksilver's Alliance System gathering agreement. We expect this customer to continue to account for a significant portion of our revenue in 2012.

Quicksilver has no contractual obligation to develop its properties in the areas covered by their dedication to us and it may determine that it is strategically more attractive to direct its capital spending and resources to other areas. A shift in Quicksilver's focus away from the areas covered by their dedication to us could result in reduced natural gas gathered and processed by us and a material decline in our revenue and cash flow. In January 2012, Quicksilver announced a reduced drilling program in the Barnett when compared to previous years.

Furthermore, the credit ratings of our largest customer, Quicksilver, are below investment grade. Accordingly, the risk of loss resulting from any material non-payment or non-performance by Quicksilver is higher than it would be with a more creditworthy customer, especially in light of the significant concentration of business conducted with Quicksilver. Unless and until we significantly diversify our customer base, we expect to remain subject to non-diversified risk of non-payment or late payment of our fees. In addition, Quicksilver is highly leveraged and subject to its own operating and regulatory risks, which could increase the risk that it may default on its obligations to us.

We may not have sufficient available cash to enable us to make cash distributions to holders of our common units at the current distribution rate under our cash distribution policy.

In order to pay the announced cash distributions of $0.49 per unit per quarter, or $1.96 per unit per year, we must generate available cash of approximately $20.7 million per quarter, or $82.8 million per year based on the number of general partner units and common units outstanding on December 31, 2011. We may not have sufficient available cash from operating surplus each quarter to enable us to pay the announced distributions. The amount of cash we can distribute depends principally upon the amount of cash we generate from our operations, which may fluctuate from quarter to quarter based on, among other things:

- the fees we charge and the margins we realize for our services;
- the level of production, and the prices of, natural gas, NGLs, and condensate;
- the volume of natural gas and NGLs we gather and process;
- the level of competition from other midstream energy companies;
- the level of our operating and maintenance and general and administrative costs;
- prevailing economic conditions;
- the level of capital expenditures we make;
- our ability to make borrowings under our Credit Facility;
- the cost of acquisitions;
- our debt service requirements;
- fluctuations in our working capital needs;
- our ability to access capital markets;
- compliance with our debt agreements; and
- the amount of cash reserves established by our General Partner.

The amount of cash we have available for distribution to holders of our common units depends primarily on our cash flow and not solely on profitability. Accordingly we may be prevented from making distributions, even during periods in which we record net income.

The amount of cash we have available for distribution depends primarily upon our cash flow and not solely on profitability, which may be affected by non-cash items. As a result, we may make cash distributions during periods when we report net losses, and conversely, we might fail to make cash distributions during periods when we report net profits.

Estimates of oil and gas reserves depend on many assumptions that may turn out to be inaccurate. Therefore, future volumes of natural gas on our systems could be less than we anticipate and could adversely affect our financial performance.

We typically do not obtain independent evaluations of natural gas reserves connected to our systems. Accordingly, we do not have independent estimates of total reserves dedicated to our systems or the anticipated life of such reserves. If the total reserves or estimated life of the reserves connected to our systems is less than we anticipate and we are unable to secure additional sources of natural gas, it could have a material adverse effect on our business, results of operations and financial condition.

Because of the natural decline in production from existing wells in our areas of operations, our success depends on our ability to obtain new sources of natural gas which is dependent on factors beyond our control. Any decrease in available supplies of natural gas could result in a material decline in the volumes we gather, process, treat and compress.

Our gathering systems are connected to wells whose production will naturally decline over time, which means that our cash flows associated with these wells will also decline over time. To maintain or increase throughput levels on our system, we must continually obtain new natural gas supplies. Our ability to obtain additional sources of natural gas depends in part on the level of successful drilling activity near our pipeline systems by our customers and our ability to compete for volumes against other midstream service providers.

While we have dedications from our customers which include certain producing and non-producing oil and gas properties, we have no control over the level of drilling activity in our areas of operations, the amount of reserves associated with the wells drilled, rate at which wells are produced or the rate at which production from a well will decline. In addition, we have no control over producers' drilling or production decisions, which are affected by, among other things, prevailing and projected energy prices, demand for hydrocarbons, the level of reserves, geological considerations, governmental regulations, availability of drilling rigs and other production and development services and the availability and cost of capital. Fluctuations in energy prices can greatly affect investments to develop natural gas reserves. Drilling activity generally decreases as natural gas prices decrease. Declines in natural gas prices could have a negative impact on exploration, development and production activity and, if sustained, could lead to a material decrease in such activity. Reductions in exploration or production activity in our areas of operations could lead to reduced utilization of our systems. Because of these factors, even if natural gas reserves are known to exist in areas served by our assets, producers may choose not to develop those reserves. Moreover, our customers are not contractually obligated to develop the reserves and or properties they have dedicated to us. If reductions in drilling activity or increased competition result in our inability to obtain new sources of supply to replace the natural decline of volumes from existing wells, throughput on our systems would decline, which could reduce our revenue, cash flow and cash available for distribution to our unitholders.

In addition, various federal and state initiatives are underway to regulate, or further investigate, the environmental impacts of hydraulic fracturing, a practice that involves the pressurized injection of water, chemicals and other substances into rock formations to stimulate hydrocarbon production. Hydraulic fracturing has also generated publicity regarding its potential environmental impact. The adoption of any future federal, state or local laws or regulations imposing additional permitting, disclosure or regulatory obligations related to, or otherwise restricting or increasing costs regarding the use of hydraulic fracturing could make it more difficult to drill certain oil and natural gas wells. As a result, the volume of natural gas or associated NGLs that we gather and process from wells that use hydraulic fracturing could be substantially reduced, which could adversely affect our business, financial condition, results of operations and cash available for distributions to our unitholders.

Our construction of new assets may not result in revenue increases and is subject to regulatory, environmental, safety, political, legal and economic risks, which could adversely affect our cash flow, results of operations and financial condition.

One of the ways we intend to grow our business is through the construction of new midstream assets. Additions or modifications to our asset base involve numerous regulatory, environmental, safety, political and legal uncertainties beyond our control and may require the expenditure of significant amounts of capital. If we undertake these projects, they may not be completed on schedule, at the budgeted cost, or at all. Moreover, our revenue may not increase as anticipated for a particular project. For instance, we may construct facilities to capture anticipated future growth in production in a region in which such growth does not materialize. Since we are not engaged in the exploration for and development of natural gas reserves, we may not have access to third party estimates of potential reserves in an area prior to constructing or acquiring facilities in such area. To the extent we rely on estimates of future production by parties in our decision to expand our systems, such estimates may prove to be inaccurate due to numerous uncertainties inherent in estimating quantities of future production. As a result, new facilities may not be able to attract enough throughput to achieve our expected investment return, which could adversely affect our results of operations and financial condition. In addition, expansion of our asset base generally requires us to obtain new rights-of-way. We may be unable to obtain such rights-of-way or it may become more expensive for us to obtain or renew rights-of-way. If the cost of rights-of-way increases, our cash flow could be adversely affected.

If we do not make acquisitions on economically acceptable terms, our future growth will be limited.

In addition to expanding our existing systems, one of our primary strategies is to pursue acquisitions, such as the Frontier Gas Acquisition and the Tristate Acquisition. If we are unable to make these acquisitions because we are: (1) unable to identify attractive acquisition candidates, to analyze acquisition opportunities successfully from an operational and financial point of view or to negotiate acceptable purchase contracts with them; (2) unable to obtain financing for these acquisitions on economically acceptable terms or (3) outbid by competitors, then our future growth could be limited. Furthermore, even if we do make acquisitions, these acquisitions may not result in an increase in the cash generated by operations.

Any acquisition involves potential risks, including, among other things:

- incorrect assumptions about volumes, revenue and costs, including synergies;
- an inability to successfully integrate the assets we acquire;
- the assumption of unknown liabilities;
- limitations on rights to indemnity from the seller;
- incorrect assumptions about the overall costs of equity or debt;
- the diversion of management's and employees' attention from other business matters;
- unforeseen difficulties of operating in new product areas, with new customers, or new geographic areas; and
- customer or key employee losses at the acquired businesses.

Any of the above risks could significantly impair our ability to manage our business and materially and adversely affect our business, results of operations and financial condition.

We depend on our midstream assets to generate our revenue, and if the utilization of these assets was reduced significantly, there could be a material adverse effect on our revenue, earnings and ability to make cash distributions to our unitholders.

Operations of our midstream assets could be partially curtailed or completely shut down, temporarily or permanently, as a result of:

- operational problems, labor difficulties or environmental proceedings or other litigation;
- catastrophic events at our facilities or at downstream facilities owned by others;
- lack of transportation or fractionation capacity;
- an inability to obtain sufficient quantities of natural gas; or
- prolonged reductions in exploration or production activity by producers in the areas in which we operate.

The magnitude of the effect on us of any curtailment of our operations will depend on the length of the curtailment and the extent of the operations affected by such curtailment. We have no control over many of the factors that may lead to a curtailment of operations. In the event that we are unable to provide either gathering, processing, treating, compression, transportation or sales services for 60 consecutive days our producers may have the right to deliver their gas to alternative pipelines. If such a termination were to occur, it could cause our revenue, earnings and cash flow to decrease.

We cannot control the operations of third party NGL fractionation and natural gas and NGL transportation facilities, and our business, results of operations, financial condition and cash available for distribution could be adversely affected.

We depend upon third-party NGL transportation and fractionation systems that we do not own. Since we do not own or operate these assets, their continuing operation is not within our control. If any of these third-party pipelines and other facilities becomes unavailable or capacity constrained, it could have a material adverse effect on our business, results of operations, financial condition and cash available for distribution 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 revenue to decline and operating expenses to increase.

Our operations are generally exempt from the jurisdiction and regulation of FERC, except that we are subject to the anti-market manipulation provisions in the Natural Gas Act, as amended by the Energy Policy Act of 2005, and to FERC's regulations thereunder, including FERC's authority to impose fines of up to one million dollars ($1,000,000) per day per violation. Notwithstanding, 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 have no assurance 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 regularly been the subject of substantial, on-going litigation. Consequently, the classification and regulation of some of our pipelines could change based on future determinations by FERC, the courts or Congress. If our gas gathering operations become subject to FERC jurisdiction, the result may adversely affect the rates we are able to charge and the services we currently provide, and may include the potential for a termination of the gathering and processing agreements with our customers.

State and municipal regulations also affect our business. Common purchaser statutes generally require gatherers to gather or provide services without undue discrimination as to source of supply or producer; as a result, these statutes restrict our right to decide whose production we gather. Federal law leaves any economic regulation of natural gas gathering to the states. The states in which we currently operate have adopted complaint-based regulation of gathering activities, which allows oil and natural gas producers and shippers to file complaints with state regulators in an effort to resolve access and rate grievances. Other state and municipal 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 our gathering lines.

We are subject to environmental laws, regulations and permits, including greenhouse gas requirements that may expose us to significant costs, liabilities and obligations.

We are subject to stringent and complex federal, state and local environmental laws, regulations and permits, relating to, among other things, the generation, storage, handling, use, disposal, movement and remediation of natural gas, NGLs, crude oil and other hazardous materials; the emission and discharge of such materials to the ground, air and water; wildlife protection; and the health and safety of our employees. Failure to comply with these environmental requirements may result in our being subject to litigation, fines or other sanctions, including the revocation of permits and suspension of operations. We may incur significant compliance related costs and other associated expenses related to such requirements.

We could be liable for any environmental contamination at our or our predecessors' currently or formerly owned or operated properties or third party waste disposal sites, regardless of whether we were at fault. In addition to potentially significant investigation and remediation costs, such matters can give rise to claims from governmental authorities and other third parties for fines or penalties, natural resource damages, personal injury and property damage.

Moreover, stricter laws, regulations or enforcement policies could significantly increase our operational or compliance costs and the cost of any remediation that may become necessary. For instance, since August 2009, the Texas Commission on Environmental Quality has conducted a series of analyses of air emissions in the

Barnett Shale area in response to reported concerns about high concentrations of benzene in the air near drilling sites and natural gas processing facilities, and the analysis could result in the adoption of new air emission regulatory or permitting limitations that could require us to incur increased capital or operating costs. Additionally, environmental groups have advocated increased regulation and a moratorium on the issuance of drilling permits for new natural gas wells in developed or developing shale areas. The adoption of any laws, regulations or other legally enforceable mandates that result in more stringent air emission limitations or that restrict or prohibit the drilling of new natural gas wells for any extended period of time could increase our operating and compliance costs as well as reduce the rate of production of natural gas operators with whom the we have a business relationship, which could have a material adverse effect on our results of operations and cash flows.

These laws, regulations and permits, and the enforcement and interpretation thereof, change frequently and generally have become more stringent over time. In particular, requirements pertaining to air emissions, including volatile organic compound emissions, have been implemented or are under development that could lead us to incur significant costs or obligations or curtail our operations. For example GHG emission regulation has become more stringent. We are currently required to report annual GHG emissions from some of our operations, and additional GHG emission-related requirements are in various stages of development. In addition, the EPA has now begun regulating GHG emissions from stationary sources pursuant to the Prevention of Significant Deterioration and Title V provisions of the federal Clean Air Act. Such regulations could require us to modify existing or obtain new permits, implement additional pollution control technology, curtail operations or increase significantly our operating costs in the future. Any regulation of GHG emissions, including through a cap-and-trade or similar emissions trading schemes, technology mandate, emissions tax, reporting requirement or other program, could adversely affect our business, reputation, operating performance and product demand. In addition, to the extent climate change results in more severe weather, our customers' operations may be disrupted, which could reduce product demand.

In addition, various federal and state initiatives are underway to regulate, or further investigate the environmental impacts of hydraulic fracturing, a practice that involves the pressurized injection of water, chemicals and other substances into rock formations to stimulate hydrocarbon production. To the extent these initiatives reduce the volume of natural gas or associated NGLs that we gather and process, they could adversely affect our business.

Our costs, liabilities and obligations relating to environmental matters could have a material adverse effect on our business, reputation, results of operations and financial condition.

We may incur costs as a result of pipeline integrity management program testing.

The DOT requires pipeline operators to develop integrity management programs for pipelines located where a leak or rupture could harm "high consequence areas." The regulations require operators, including us, to:

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

We currently estimate that we will incur total future costs of approximately $1 million through 2016 to complete the testing required by existing DOT regulations. This estimate does not include the costs, if any, for repair, remediation, preventative or mitigating actions that may be determined to be necessary as a result of the testing program itself.

We may incur costs as a result of additional pipeline safety legislation.

The Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011 was enacted by Congress in December 2011 and signed into law by the President on January 3, 2012. In addition to reauthorizing federal pipeline safety programs through 2015, this legislation adopts additional safety requirements and reforms and increases penalties for safety violations. The PHMSA has also published an advanced notice of proposed rulemaking to solicit comments on the need for changes to its safety regulations, including whether to revise the integrity management requirements and add new regulations governing the safety of gathering lines. Such legislative and regulatory changes could have a material effect on our operations through more stringent and comprehensive safety regulations and higher penalties for the violation of those regulations.

Our level of indebtedness could adversely affect our ability to raise additional capital to fund our operations, limit our ability to react to changes in our business or our industry and place us at a competitive disadvantage.

As of December 31, 2011, the total outstanding principal amount of our long-term indebtedness was $512.5 million, consisting of approximately $312.5 million outstanding under our Credit Facility, bearing an effective weighted average interest rate of 3.3%, and $200 million aggregate principal amount of 7.75% Senior Notes due 2019 ("Senior Notes"). We used $102.8 million in net proceeds from our equity offering in January 2012 to reduce borrowing under our Credit Facility. For the year ended December 31, 2011, 2010 and 2009, our consolidated interest expense was $27.6 million, $13.6 million and $8.5 million, respectively.

Our inability to generate sufficient cash flow to satisfy our debt obligations or to obtain alternative financing could materially and adversely affect our business, results of operations, financial condition and business prospects.

Our substantial debt could have important consequences to our unitholders. For example, it could:

- increase our vulnerability to general adverse economic and industry conditions;
- limit our ability to fund future capital expenditures and working capital, to engage in development activities, or to otherwise realize the value of our assets and opportunities fully because of the need to dedicate a substantial portion of our cash flow from operations to payments of interest and principal on our debt or to comply with any restrictive covenants or terms of our debt;
- result in an event of default if we fail to satisfy our obligations with respect to our indebtedness or fail to comply with the financial and other restrictive covenants contained in the agreements governing our indebtedness, which event of default could result in all of our debt becoming immediately due and payable and could permit our lenders to foreclose on any of the collateral securing such debt;
- in the event of default or a default being created by a distribution, we will be prohibited to declare or pay a distribution;
- require a substantial portion of cash flow from operations to be dedicated to the payment of principal and interest on our indebtedness, therefore reducing our ability to use our cash flow to fund our operations, capital expenditures and future business opportunities;
- increase our cost of borrowing;
- restrict us from making strategic acquisitions or causing us to make non-strategic divestitures;
- limit our flexibility in planning for, or reacting to, changes in our business or industry in which we operate, placing us at a competitive disadvantage compared to our peers who are less highly leveraged and who therefore may be able to take advantage of opportunities that our leverage prevents us from exploring; and
- impair our ability to obtain additional financing in the future.

Realization of any of these factors could adversely affect our financial condition, results of operations and cash flows.

If we are unable to obtain needed capital or financing on satisfactory terms, our ability to make cash distributions may be diminished and our financial leverage could increase.

Historically, we have used our cash flow from operations, borrowings under our Credit Facility and issuances of equity to fund our capital program, working capital needs and acquisitions. Our capital program may require additional financing above the level of cash generated by our operations to fund our growth. If our cash flow from operations decreases as a result of lower throughput volumes on our gathering and processing systems or otherwise, our ability to expend the capital necessary to expand our business or increase our future cash distributions may be limited. If our cash flow from operations is insufficient to satisfy our financing needs, we cannot be certain that additional financing will be available to us on acceptable terms or at all. Our ability to obtain bank financing or to access the capital markets for future equity or debt offerings may be limited by our financial condition or general economic conditions at the time of any such financing or offering. Even if we are successful in obtaining the necessary funds, the terms of such financings could have a material adverse effect on our business, results of operation, financial condition and ability to make cash distributions to our unitholders. Further, incurring additional debt may significantly increase our interest expense and financial leverage and issuing additional limited partner interests may result in significant unitholder dilution and would increase the aggregate amount of cash required to maintain the cash distribution rate which could materially decrease our ability to pay distributions. If additional capital resources are unavailable, we may curtail our activities or be forced to sell some of our assets on an untimely or unfavorable basis.

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, which subjects us to the possibility of more onerous terms or increased costs to obtain and maintain valid easements and rights-of-way. We obtain standard easement rights to construct and operate our pipelines on land owned by third parties. Our rights generally revert back to the landowner after we stop using the easement for its specified purpose. Therefore, these easements exist for varying periods of time. Our loss of easement rights could have a material adverse effect on our ability to operate our business, thereby resulting in a material reduction in our revenue, earnings and ability to make cash distributions to our unitholders.

Our business involves many hazards and operational risks, some of which may not be adequately covered by insurance. The occurrence of a significant accident or other event that is not adequately insured could curtail our operations and have a material adverse effect on our business, results of operations, financial condition and ability to make cash distributions to our unitholders.

Our operations are subject to many risks inherent in the midstream industry including:

- damage to pipelines and plants, related equipment and surrounding properties caused by natural disasters and acts of terrorism;
- inadvertent damage from construction, farm and utility equipment;
- leaks or losses of natural gas or NGLs as a result of the malfunction of equipment or facilities;
- fires and explosions;
- cyber intrusions; and
- other hazards that could also result in personal injury, loss of life, pollution or suspension of operations.

These risks could result in curtailment or suspension of our related operations. A natural disaster or other hazard affecting the areas in which we operate could have a material adverse effect on our operations. Hostile cyber intrusions, including those targeting sensitive customer information, employee and vendor information maintained by us in the normal course of business, as well as breaches in the technology used in our business processes, could severely disrupt business operations and result in loss of service to customers, as well as significant expense to repair security breaches or system damage We maintain insurance against some, but not all, of such risks and losses in accordance with customary industry practice. For example, we do not have any property insurance on any of our underground pipeline systems that would cover damage to the pipelines. We are not insured against all environmental incidents, claims or damages that might occur. Any significant accident or event that is not adequately insured could adversely affect our business, results of operations and financial condition. In addition, we may be unable to economically obtain or maintain the insurance that we desire. As a result of market conditions, premiums and deductibles for certain of our insurance policies could escalate further. In some instances, certain insurance could become unavailable or available only at reduced coverage levels. Any type of catastrophic event could have a material adverse effect on our business, results of operations, financial condition and ability to make cash distributions to our unitholders.

The loss of key personnel could adversely affect our ability to operate.

Our success is dependent upon the efforts of our senior management, as well as on our ability to attract and retain senior management. Our senior executive officers have significant experience in the natural gas industry and have developed strong relationships with a broad range of industry participants. The loss of any of these executives could prevent us from implementing our business strategy and have a material adverse effect on our relationships with these industry participants, our results of operations and ability to make cash distributions to our unitholders.

We do not have employees. We rely solely on officers and employees of Crestwood Holdings to operate and manage our business.

We are currently solely reliant on the performance of our midstream business and assets, and as a result of this lack of diversification, our ability to make distributions to our unitholders could be adversely impacted.

Given the concentration inherent in our business, in that it is entirely reliant on the revenues and cash flows generated from our midstream business and its assets, any adverse developments in the midstream energy industry could impact our ability to generate sufficient cash flows, which could affect the level of distributions to our unitholders.

If we fail to maintain effective internal control over financial reporting, we may have material misstatements in our financial statements, and we may not be able to report our financial results in a timely and reliable manner.

We have established internal controls over financial reporting. However, internal controls over financial reporting may not prevent or detect misstatements because of their inherent limitations, including the possibility of human error, the circumvention or overriding of controls or fraud. Therefore, even effective internal controls can provide only reasonable assurance with respect to the preparation and fair presentation of financial statements. If we fail to maintain the adequacy of our internal controls, we may be unable to provide financial information in a timely and reliable manner. Any such difficulties or failure may have a material adverse effect on our business, financial condition and operating results.

During the course of the preparation of our financial statements, we evaluate our internal controls to identify and remediate deficiencies in our internal controls over financial reporting. In the event we are unable to identify and correct deficiencies in our internal controls in a timely manner, we may not record, process, summarize and report financial information accurately and within the time periods required for our financial reporting under the terms of the agreements governing our indebtedness or within the required deadlines established by the SEC.

In the fourth quarter of 2011, we became aware of deficiencies in controls relating to (i) the preparation of pro forma financial information that was required to be disclosed in the notes to our condensed consolidated financial statements in connection with an acquisition and (ii) our classification of the receipt of proceeds from our Class C unit offering on April 1, 2011 as an operating activity instead of a financing activity. We have concluded that such deficiencies identified in clause (i) of the previous sentence represented material weaknesses in internal control over financial reporting. As a result of these material weaknesses and deficiencies in control, as appropriate, errors occurred in our interim condensed consolidated financial statements related to (i) the presentation of pro forma financial information disclosed in the footnotes to the condensed consolidated financial statements and (ii) our condensed consolidated statement of cash flows. These errors ultimately resulted in amendments to our quarterly reports on Form 10-Q/A for the periods ended March 31, 2011, June 30, 2011 and September 30, 2011.

Although we are implementing additional controls related to financial reporting disclosures for acquisitions and additional review procedures by individuals with expertise in U.S. generally accepted accounting principles ("GAAP") and SEC financial reporting standards, we may fail to maintain effective internal control over financial reporting in the future. Failure to maintain effective internal control over financial reporting could result in investigations or sanctions by regulatory authorities, cause unitholders to lose confidence in our reported financial condition, lead to a default under our Credit Facility and otherwise materially adversely affect our business, financial condition and results of operations.

Risk Inherent to an Investment in Us

Crestwood Holdings owns and controls our General Partner, which has sole responsibility for conducting our business and managing our operations. Crestwood Holdings and our General Partner have conflicts of interest with, and may favor, Crestwood Holdings' interests to the detriment of our unitholders.

Crestwood Holdings owns and controls our General Partner, and appoints all of the directors of our General Partner. Some of our General Partner's directors, and some of its executive officers, are directors or officers of Crestwood Holdings or its affiliates. Although our General Partner has a fiduciary duty to manage us in a manner beneficial to us and our unitholders, the directors and officers of our General Partner have a fiduciary duty to manage our General Partner in a manner beneficial to Crestwood Holdings. Therefore, conflicts of interest may arise between Crestwood Holdings and its affiliates, including our General Partner, on the one hand, and us and our unitholders, on the other hand. In resolving these conflicts of interest, our General Partner may favor its own interests and the interests of its affiliates over the interests of our unitholders.

Crestwood Holdings is not limited in its ability to compete with us and is not obligated to offer us the opportunity to acquire additional assets or businesses, which could limit our ability to grow and could adversely affect our results of operations and cash available for distribution to our unitholders.

Crestwood Holdings is not prohibited from owning assets or engaging in businesses that compete directly or indirectly with us. In addition, in the future, Crestwood Holdings may acquire, construct or dispose of additional midstream or other assets and may be presented with new business opportunities, without any obligation to offer us the opportunity to purchase or construct such assets or to engage in such business opportunities. Moreover, while Crestwood Holdings may offer us the opportunity to buy assets from it or to participate in investments with it, it is under no contractual obligation to do so and we are unable to predict whether or when such acquisitions might be completed.

Cost reimbursements due to Crestwood Holdings and our General Partner for services provided to us or on our behalf will be substantial and will reduce our cash available for distribution to our unitholders. The amount and timing of such reimbursements will be determined by our General Partner.

Prior to making distributions on our common units, we will reimburse our General Partner and its affiliates for all expenses they incur on our behalf. These expenses will include all costs incurred by Crestwood Holdings and our General Partner in managing and operating us. Our Second Amended and Restated Agreement of

Limited Partnership of CMLP, dated February 19, 2008, as amended ("Partnership Agreement") provides that our General Partner will determine in good faith the expenses that are allocable to us. The reimbursements to Crestwood Holdings and our General Partner will reduce the amount of cash otherwise available for distribution to our unitholders.

If you are not an eligible holder, you may not receive distributions or allocations of income or loss on your common units, and your common units will be subject to redemption.

We have adopted certain requirements regarding those investors who may own our common units. Eligible holders are U.S. individuals or entities subject to U.S. federal income taxation on the income generated by us or entities not subject to U.S. federal income taxation on the income generated by us, so long as all of the entity's owners are U.S. individuals or entities subject to such taxation. If you are not an eligible holder, our General Partner may elect not to make distributions or allocate income or loss on your units and you run the risk of having your units redeemed by us at the lower of your purchase price cost and the then-current market price. The redemption price will be paid in cash or by delivery of a promissory note, as determined by our General Partner.

Our General Partner's liability regarding our obligations is limited.

Our General Partner included provisions in its and our contractual arrangements that limit its liability under contractual arrangements so that the counterparties to such arrangements have recourse only against our assets, and not against our general partner or its assets. Our General Partner may therefore cause us to incur indebtedness or other obligations that are nonrecourse to our General Partner. Our Partnership Agreement provides that any action taken by our General Partner to limit its liability is not a breach of our General Partner's fiduciary duties, even if we could have obtained more favorable terms without the limitation on liability. In addition, we are obligated to reimburse or indemnify our General Partner to the extent that it incurs obligations on our behalf. Any such reimbursement or indemnification payments may adversely affect our business, results of operations and financial condition and would reduce the amount of cash otherwise available for distribution to our unitholders.

Our Partnership Agreement requires that we distribute all of our available cash, which could limit our ability to grow and make acquisitions.

We expect that we will distribute all of our available cash to our unitholders and will rely primarily upon external financing sources, including commercial bank borrowings and the issuance of debt and equity securities, to fund our acquisitions and expansion capital expenditures. As a result, to the extent we are unable to finance growth externally, our cash distribution policy will significantly impair our ability to grow.

In addition, because we distribute all of our available cash, our growth may not be as fast as that of businesses that reinvest their available cash to expand ongoing operations. To the extent we issue additional units in connection with any acquisitions or expansion capital expenditures, the payment of distributions on those additional units may increase the risk that we will be unable to maintain or increase our per-unit distribution level. There are no limitations in our Partnership Agreement or in Crestwood Holdings' credit facility, on our ability to issue additional units, including units ranking senior to the common units. The incurrence of additional commercial borrowings or other debt to finance our growth strategy would result in increased interest expense, which, in turn, may adversely affect our business, results of operations and financial condition and impact the available cash that we have to distribute to our unitholders.

Our General Partner may elect to cause us to issue Class B and general partner units to it in connection with a resetting of the target distribution levels related to its incentive distribution rights, without the approval of the special committee of its board of directors or the holders of our common units. This could result in lower distributions to holders of our common units.

Our General Partner has the right, at any time when there are no subordinated units outstanding and it has received incentive distributions at the highest level to which it is entitled (48% for each of the prior four consecutive fiscal quarters), to reset the initial target distribution levels at higher levels based on our distributions at the time of the exercise of the reset election. Following a reset election by our General Partner, the minimum quarterly distribution will be adjusted to equal the reset minimum quarterly distribution and the target distribution levels will be reset to correspondingly higher levels based on percentage increases above the reset minimum quarterly distribution.

If our General Partner elects to reset the target distribution levels, it will be entitled to receive a number of Class B units and general partner units. The Class B units will be entitled to the same cash distributions per unit as our common units and will be convertible into an equal number of common units. The number of Class B units to be issued to our General Partner will be equal to that number of common units which would have entitled their holder to an average aggregate quarterly cash distribution in the prior two quarters equal to the average of the distributions to our General Partner on the incentive distribution rights in the prior two quarters. Our General Partner will be issued the number of general partner units necessary to maintain an interest in us, equivalent to the interest that existed immediately prior to the reset election. We anticipate that our General Partner would exercise this reset right in order to facilitate acquisitions or internal growth projects that would not be sufficiently accretive to cash distributions per common unit without such conversion. It is possible, however, that our General Partner could exercise this reset election at a time when it is experiencing, or expects to experience, declines in the cash distributions it receives related to its incentive distribution rights and may, therefore, desire to be issued Class B units, which are entitled to distributions on the same priority as our common units, rather than retain the right to receive incentive distributions based on the initial target distribution levels. As a result, a reset election may cause our common unitholders to experience a reduction in the amount of cash distributions that they would have otherwise received had we not issued new Class B units and general partner units to our General Partner in connection with resetting the target distribution levels.

Holders of our common units have limited voting rights and are not entitled to elect our General Partner or its directors.

Unlike the holders of common stock in a corporation, unitholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management's decisions regarding our business. Unitholders will have no right on an annual or ongoing basis to elect our General Partner or its board of directors. The board of directors of our General Partner is chosen by the sole member of Crestwood Gas Services Holdings LLC. Furthermore, if the unitholders are dissatisfied with the performance of our General Partner, they will have little ability to remove our General Partner. As a result of these limitations, the price at which the common units will trade could be diminished because of the absence or reduction of a takeover premium in the trading price. Our Partnership Agreement also 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.

Even if holders of our limited partner units are dissatisfied, they cannot initially remove our General Partner without its consent.

The unitholders initially will be unable to remove our General Partner without its consent because our General Partner and its affiliates currently own sufficient units to be able to prevent its removal. The vote of the holders of at least 66 2/3% of all outstanding limited partner units voting together as a single class is required to remove our General Partner. As of December 31, 2011, the General Partner and Crestwood Holdings beneficially owned 48.5% of our outstanding limited partner units. As of February 13, 2012, the General Partner and Crestwood Holdings beneficially owned 44.5% of our limited partner units, subsequent to the issuance of the 3,500,000 common limited partner units on January 13, 2012.

Our Partnership Agreement restricts the voting rights of certain unitholders owning 20% or more of our common units.

Unitholders' voting rights are further restricted by a provision of our Partnership Agreement providing that any units held by a person that owns 20% or more of any class of units then outstanding, other than our General Partner, its affiliates, their transferees and persons who acquired such units with the prior approval of the board of directors of our General Partner, cannot vote on any matter.

Our General Partner interest or the control of our General Partner may be transferred to a third party without unitholder consent.

Our General Partner may transfer its General Partner interest to a third party in a merger or in a sale of all or substantially all of its assets without the consent of the unitholders. Furthermore, our Partnership Agreement does not restrict the ability of Crestwood Holdings to transfer all or a portion of its ownership interest in our General Partner to a third party. In such a case, the new owner of our General Partner would then be in a position to replace the board of directors and officers of our General Partner with its own designees and thereby exert significant control over the decisions made by the board of directors and officers.

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

Our Partnership Agreement does not limit the number of additional limited partner interests that we may issue at any time without the approval of our unitholders. The issuance by us of additional common units or other equity securities of equal or senior rank will have the following effects:

- our existing unitholders' proportionate ownership interest in us will decrease;
- the amount of cash available for distribution on each unit may decrease;
- the ratio of taxable income to distributions may increase;
- the relative voting strength of each previously outstanding unit may be diminished; and
- the market price of the common units may decline.

Crestwood Holdings may sell units in the public or private markets, and such sales could have an adverse impact on the trading price of the common units.

As of December 31, 2011, Crestwood Holdings beneficially holds an aggregate of 19,544,089 common units. The sale of any or all of these units in the public or private markets could have an adverse impact on the price of the common units or on any trading market on which common units are traded.

Our General Partner has a limited call right that may require existing unitholders to sell their 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, which it may assign to any of its affiliates or to us, but not the obligation, to acquire all, but not less than all, of the common units held by unaffiliated persons at a price that is not less than their then-current market price. As a result, existing unitholders may be required to sell their common units at an undesirable time or price and may not receive any return on their investment. Existing unitholders may also incur a tax liability upon a sale of their units. As of December 31, 2011, the General Partner and Crestwood Holdings beneficially owned 48.5% of our outstanding limited partner units. As of February 13, 2012 the General Partner and Crestwood Holdings beneficially owned 44.5% of our limited partner units, subsequent to the issuance of the 3,500,000 common limited partner units on January 13, 2012.

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

A general partner of a partnership generally has unlimited liability for the obligations of the partnership, except for those contractual obligations of the partnership that are expressly made without recourse to the general partner. 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. A unitholder could be liable in some circumstances for any and all of our obligations as if that unitholder were a general partner if a court or government agency were to determine that:

- we were conducting business in a state but had not complied with the applicable limited partnership statute; or
- unitholder's right to act with other unitholders to remove or replace our General Partner, to approve some amendments to our Partnership Agreement or to take other actions under our partnership agreement constitute "control" of our business.

Unitholders may have liability to repay distributions that were wrongfully distributed to them.

Under certain circumstances, unitholders may have to repay amounts wrongfully returned or distributed to them. Under Section 17-607 of the Delaware Revised Uniform Limited Partnership Act, we may not make a distribution to unitholders if the distribution would cause our liabilities to exceed the fair value of our assets. Delaware law provides that for a period of three years from the date of an impermissible distribution, limited partners who received the distribution and who knew at the time of the distribution that it violated Delaware law will be liable to the limited partnership for the distribution amount. Substituted limited partners are liable both for the obligations of the assignor to make contributions to the partnership that were known to the substituted limited partner at the time it became a limited partner and for those obligations that were unknown if the liabilities could have been determined from the Partnership Agreement. Neither liabilities to partners on account of their partnership interest nor liabilities that are non-recourse to the partnership are counted for purposes of determining whether a distribution is permitted.

The market price of our common units could be volatile due to a number of factors, many of which are beyond our control.

The market price of our common units could be subject to wide fluctuations in response to a number of factors, most of which we cannot control, including, changes in securities analysts' recommendations; public's reaction to our press releases, announcements and our filings with the SEC; fluctuations in broader securities market prices and volumes, particularly among securities of midstream companies and securities of publicly-traded limited partnerships; changes in market valuations of similar companies; departures of key personnel; commencement of or involvement in litigation; variations in our quarterly results of operations or those of midstream companies; variations in the amount of our quarterly cash distributions; future issuances and sales of our common units; availability of, and sufficient access to, capital; and changes in general conditions in the U.S. economy, financial markets or the midstream industry.

TAX RISKS TO COMMON UNITHOLDERS

Our tax treatment depends on our being treated as a partnership for federal income tax purposes, as well as our not being subject to a material amount of additional entity-level taxation by individual states. If the Internal Revenue Service were to treat us as a corporation or if we become subject to a material amount of additional entity-level taxation for state tax purposes, then it would substantially reduce the amount of cash available for distribution to our unitholders.

The anticipated after-tax economic benefit of an investment in the common units depends largely on our being treated as a partnership for federal income tax purposes. As long as we qualify to be treated as a partnership for federal income tax purposes, in general we will not be subject to federal income tax. Although a publicly-traded limited partnership is generally treated as a corporation for federal income tax purposes, a publicly-traded partnership such as us can qualify to be treated as a partnership for federal income tax purposes under current law so long as for each taxable year at least 90% of its gross income is derived from specified investments and activities. We believe that we qualify to be treated as a partnership for federal income tax purposes because we believe that at least 90% of our gross income for each taxable year has been and is derived from such specified investments and activities. Although we intend to meet this gross income requirement, we may not find it possible, regardless of our efforts, to meet this gross income requirement or may inadvertently fail to meet this gross income requirement. If we do not meet this gross income requirement for any taxable year and the Internal Revenue Service, or IRS, does not determine that such failure was inadvertent, we would be treated as a corporation for such taxable year and each taxable year thereafter. We have not requested, and do not plan to request, a ruling from the IRS on this or any other tax matter affecting us.

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rate, which is currently a maximum of 35 percent. If we were treated as a corporation at the state level, we would likely also be subject to entity-level state income tax at varying rates. Moreover, 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 or other forms of taxation. We are for example, subject to an entity-level tax in Texas. The imposition of any entity-level taxation, including a federal income tax imposed on us as a corporation or any entity-level state taxes, will reduce the amount of cash we can distribute each quarter to the holders of our common units. Therefore, our treatment as a corporation for federal income tax purposes or becoming subject to a material amount of additional state taxes could result in a material reduction in the anticipated cash flow and after-tax return to the unitholders, likely causing a substantial reduction in the value of our common units.

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

The present U.S. federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by administrative, legislative or judicial interpretation at any time. For example, members of Congress have considered substantive changes to the existing U.S. tax laws including the definition of qualifying income under Section 7704(d) of the Internal Revenue Code and the treatment of certain types of income earned from profits interests in 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, President Obama has recently urged Congress to consider tax reform pursuant to a Joint Report by The White House and The Department of the Treasury titled The President's Framework for Business Tax Reform released February 2012. Among the President's proposals is to establish greater parity between large corporations and large non-corporate counterparts which could include entity level taxation for publicly traded partnerships, including us. 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. Furthermore, any modification to the federal income tax laws and interpretations thereof may or may not be applied retroactively and could make it more difficult or impossible for us to meet the exception to be treated as a partnership for U.S. federal income tax purposes that is not taxable as a corporation, 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, adversely affect an investment in our common units or otherwise negatively impact the value of an investment in our common units.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our 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. 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.

An Internal Revenue Service contest of the federal income tax positions we have taken or may take may adversely affect the market for our common units, and the cost of any Internal Revenue Service contest will reduce our cash available for distribution to our unitholders.

We have not requested any ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes or any other matter affecting us. The IRS may adopt positions that differ from the positions we have taken or may take. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we have taken or may take. A court may not agree with some or all the positions we have taken or may take. Any contest with the IRS may materially and adversely impact the market for our common units and the price at which they trade. In addition, the costs of any contest with the IRS will result in a reduction in cash available to pay distributions to our unitholders and our General Partner and thus will be borne indirectly by our unitholders and our General Partner.

Unitholders will be required to pay taxes on their share of our income even if they do not receive any cash distributions from us.

Because our unitholders will be treated as partners to whom we will allocate taxable income which could be different in amount than cash we distribute, they will be required to pay federal income taxes and, in some cases, state, local and foreign income taxes on their allocable share of our taxable income, whether or not cash is distributed from us. Cash distributions may not equal a unitholder’s share of our taxable income or even equal the actual tax liability that results from the unitholder’s allocable share of our taxable income.

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

If our unitholders sell units, they will recognize a gain or loss equal to the difference between the amount realized and their tax basis in those common units. Prior distributions to them in excess of the total net taxable income they were allocated for a common unit, which decreased their tax basis in that common unit, will, in effect, become taxable income to them 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, regardless of whether such amount represents gain, may be taxed as ordinary income to our unitholders due to potential recapture items, including depreciation recapture. In addition, if they 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 employee benefit plans, individual retirement accounts ("IRAs") Keogh plans and other retirement plans, regulated investment companies, real estate investment trusts, mutual funds and non-United States persons raises issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and will be taxable to them. Distributions to non-United States persons will be reduced by withholding taxes at the highest applicable effective tax rate, and non-United States persons will be required to file United States federal income tax returns and pay tax on their share of our taxable income. Tax-exempt entities or foreign persons should consult their tax advisor regarding their investment in our common units.

We will treat each purchaser of units as having the same tax benefits without regard to the actual common units purchased. The IRS may challenge this treatment, which could result in a unitholder owing more tax and could otherwise adversely affect the value of the common units.

Because we cannot match transferors and transferees of common units, we will adopt depreciation and amortization positions that may not conform to all aspects of existing Treasury Regulations. Any position we take that is inconsistent with applicable Treasury Regulations may have to be disclosed on our federal income tax return. This disclosure increases the likelihood that the IRS will challenge our positions and propose adjustments to some or all of our unitholders. 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 their sale of our common units and could have a negative impact on the value of our common units or result in audit adjustments to their tax returns.

We may adopt certain valuation methodologies that may result in a shift of income, gain, loss and deduction between the general partner and the unitholders. The IRS may challenge this treatment, which could adversely affect the value of the common units.

When we issue additional units or engage in certain other transactions, we will determine the fair market value of our assets and allocate any unrealized gain or loss attributable to our assets to the capital accounts of our unitholders and our General Partner. Our methodology may be viewed as understating the value of our assets. In that case, there may be a shift of income, gain, loss and deduction between certain unitholders and the general partner, which may be unfavorable to such unitholders. Moreover, under our methodologies, subsequent purchasers of common units may have a greater portion of their Internal Revenue Code Section 743(b) adjustment allocated to our tangible assets and a lesser portion allocated to our intangible assets. The IRS may challenge our methods, or our allocation of the Section 743(b) adjustment attributable to our tangible and intangible assets, and allocations of income, gain, loss and deduction between the general partner and certain of our unitholders.

A successful IRS challenge to these methods or allocations could adversely affect the amount of taxable income or loss being allocated to our unitholders. It also could affect the amount of gain from our unitholders' sale of common units and could have a negative impact on the value of the common units or result in audit adjustments to our unitholders' tax returns without the benefit of additional deductions.

The sale or exchange of 50 percent or more of our capital and profits interests during any 12-month period will result in the termination of our partnership for federal income tax purposes.

We will be considered to have terminated our partnership for federal income tax purposes if there is a sale or exchange of 50 percent or more of the total interests in our capital and profits within a twelve-month period. Our termination would, among other things, result in the closing of our taxable year for all unitholders and could result in a deferral of depreciation deductions allowable in computing our taxable income. 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 federal tax purposes. If treated as a new partnership for federal tax purposes, we must make new tax elections and could be subject to penalties if we are unable to determine that a termination occurred.

Unitholders may become subject to state and local taxes and return filing requirements in states where they do not live as a result of their investment in our common units.

In addition to federal income taxes, unitholders will likely be subject to other taxes, including foreign, state and local 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, even if they do not live in any of those jurisdictions. Unitholders will likely be required to file state and local income tax returns and pay state and local income taxes in some or all of these various jurisdictions. Further, unitholders may be subject to penalties for failure to comply with those requirements. As we make acquisitions or expand our business, we may own assets or conduct business in additional states that impose an income tax. It is the unitholder's responsibility to file all required federal, foreign, state and local tax returns.

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

Because a unitholder whose common units are loaned to a "short seller" to cover a short sale of common units may be considered as having disposed of those common units, such unitholder may no longer be treated as a partner with respect to those common 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 common units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those common units could be fully taxable as ordinary income. 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 common units.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

A detailed description of our properties and associated 2011 developments is included in Part I, Item 1, "Business" of this report and is incorporated herein by reference.

Item 3. Legal Proceedings

In May 2011, a putative class action lawsuit, Ginardi v. Frontier Gas Services, LLC, et al, was filed in the United States District Court of the Eastern District of Arkansas against Frontier Gas Services, LLC, Chesapeake Energy Corporation, BHP Billiton Petroleum, Kinder Morgan Treating, LP, and Crestwood Arkansas Pipeline LLC (which was served in August 2011) No 4:11-cv-0420 BRW. The lawsuit alleges that the defendants' operations pollute the atmosphere, groundwater, and soil with allegedly harmful gases, chemicals, and compounds and the facilities create excessive noise levels constituting trespass, nuisance and annoyance ("Ginardi case"). In December 2011, a putative class action lawsuit, George Bartlett, et al, v. Frontier Gas Services, LLC, et al including Crestwood Arkansas Pipeline, LLC, Chesapeake Energy Corporation, and Kinder Morgan Treating LP, was filed in the United States District Court of the Eastern District of Arkansas, No 4:11-cv-0910 BSM alleging the same causes as in the Ginardi case ("Bartlett case"). In each of the Ginardi and the Bartlett case, the plaintiffs seek compensatory and punitive damages of loss of use and enjoyment of property, contamination of soil and ground water, air and atmosphere and seek future monitoring. We have filed answers in the Ginardi and Bartlett case denying any liability. The court has not certified either lawsuit as a class action. While we cannot reasonably quantify our ultimate liability, if any, for the payment of any damages or other remedial actions, neither the Ginardi nor the Bartlett cases have had, nor are they expected to have, a material impact on our results of operation, cash flows or financial condition. We intend to vigorously defend against both claims and to mitigate any clams by pursuing any indemnification obligations to which we may be entitled with respect to the properties as well as any coverage from our insurance.

From time-to-time, we are party to certain legal, regulatory or administrative proceedings that arise in the ordinary course and are incidental to our business. However, except as set forth above, there are currently no such pending proceedings to which we are a party that our management believes will have a material adverse effect on our results of operations, cash flows or financial condition. However, future events or circumstances, currently unknown to management, will determine whether the resolution of any litigation or claims will ultimately have a material effect on our results of operations, cash flows or financial condition in any future reporting periods.

Item 4. Mine Safety Disclosures

Not Applicable.

PART II

Item 5. Market For Registrant's Common Equity, Related Stockholder Matters and Issuer Purchase of Equity Securities

Market Information

Our common units are currently traded on the NYSE under the symbol "CMLP." The following table sets forth the high and low sales prices of our common units and the per unit distributions paid for the periods indicated below and are recorded when paid.

Quarter Ended	High	Low	Distributions Per Common Unit	Record Date	Payment Date
2010					
March 31, 2010	$21.56	$17.67	$0.39	May 4, 2010	May 14, 2010
June 30, 2010	$22.30	$16.08	$0.42	Aug. 3, 2010	Aug. 13, 2010
September 30, 2010	$24.99	$18.55	$0.42	Nov. 2, 2010	Nov. 12, 2010
December 31, 2010	$29.47	$24.30	$0.43	Feb. 1, 2011	Feb. 11, 2011
2011					
March 31, 2011	$31.78	$27.00	$0.44	May 3, 2011	May 13, 2011
June 30, 2011	$33.00	$26.50	$0.46	Aug. 2, 2011	Aug. 12, 2011
September 30, 2011	$28.15	$21.72	$0.48	Nov. 1, 2011	Nov. 10, 2011
December 31, 2011	$32.58	$22.00	$0.49	Jan. 31, 2012	Feb. 10, 2012

The last reported sale price of our common units on the NYSE on February 13, 2012, was $27.82. As of that date, we had 11 holders of record of our common units, including Cede & Co., as nominee for the Depository Trust Company, which held of record 16,994,139 common units. As of February 13, 2012, we have also issued and outstanding 6,716,730 Class C units, which were held of record by 16 holders, and 763,892 general partner units.

Distribution of Available Cash

General. Our Partnership Agreement requires that, within 45 days after the end of each quarter, we distribute all of our available cash to unitholders of record on the applicable record date, as determined by our General Partner.

Definition of Available Cash. The term "available cash," for any quarter, consists of all cash on hand at the end of that quarter:

- *less* the amount of cash reserves established by our General Partner to:
  - comply with applicable law, any of our debt instruments or other agreements; or
  - provide funds for distribution to our unitholders and to our General Partner for any one or more of the next four quarters;
- *plus*, if our General Partner so determines, all or a portion of cash on hand on the date of determination of available cash for the quarter resulting from working capital borrowings made subsequent to the end of such quarter; and
- *plus*, if our General Partner so determines, all or a portion of available working capital borrowings on the date of determination of available cash for such quarter.

Working capital borrowings are generally borrowings that are made under a Credit Facility or another arrangement, are used solely for working capital purposes or to pay distributions to unitholders and are intended to be repaid within 12 months. Available working capital borrowings means, on the date of determination, any amounts available to be borrowed as working capital borrowings.

Minimum Quarterly Distribution. We intend to distribute to the holders of common units on a quarterly basis at least the minimum quarterly distribution of $0.30 per unit, or $1.20 per year, to the extent we have sufficient cash from our operations after establishment of cash reserves and payment of fees and expenses, including payments to our general partner. However, there is no guarantee that we will pay the minimum quarterly distribution on the units in any quarter. Even if our cash distribution policy is not modified or revoked, the amount of distributions paid under our policy and the decision to make any distribution is determined by our General Partner, taking into consideration the terms of our Partnership Agreement. We will be prohibited from making any distributions to unitholders if it would cause an event of default or an event of default exists, under our Credit Facility (or indentures).

General Partner Interest and Incentive Distribution Rights. Our General Partner is currently entitled to 1.74% of all quarterly distributions that we make prior to our liquidation. As of February 13, 2012 our general partner interest is represented by 763,892 general partner units. Our General Partner has the right, but not the obligation, to contribute a proportional amount of capital to us to maintain its current general partner interest. The General Partner's 1.74% interest in these distributions will be reduced if we issue additional units in the future and our General Partner does not contribute a proportional amount of capital to us to maintain its 1.74% general partner interest.

Our General Partner also currently holds incentive distribution rights that entitle it to receive increasing percentages, up to a maximum of 49.74%, of the cash we distribute from operating surplus in excess of $0.4500 per unit per quarter. The maximum distribution of 49.74% includes distributions paid to our General Partner on its 1.74% general partner interest and assumes that our General Partner maintains its general partner interest at 1.74%. The maximum distribution of 49.74% does not include any distributions that our General Partner may receive on limited partner units that it owns.

The following table illustrates the percentage allocations of available cash from operating surplus between the unitholders and our General Partner based on the specified target distribution levels. The amounts set forth under "Marginal Percentage Interest in Distributions" are the percentage interests of our General Partner and the unitholders in any available cash from operating surplus we distribute up to and including the corresponding amount in the column "Total Quarterly Distribution Per Unit," until available cash from operating surplus we distribute reaches the next target distribution level, if any. The percentage interests shown for the unitholders and the General Partner for the minimum quarterly distribution are also applicable to quarterly distribution amounts that are less than the minimum quarterly distribution. The percentage interests set forth below for our General Partner include its 1.74% general partner interest and assume our General Partner has contributed any additional capital to maintain its 1.74% general partner interest and has not transferred its incentive distribution rights.

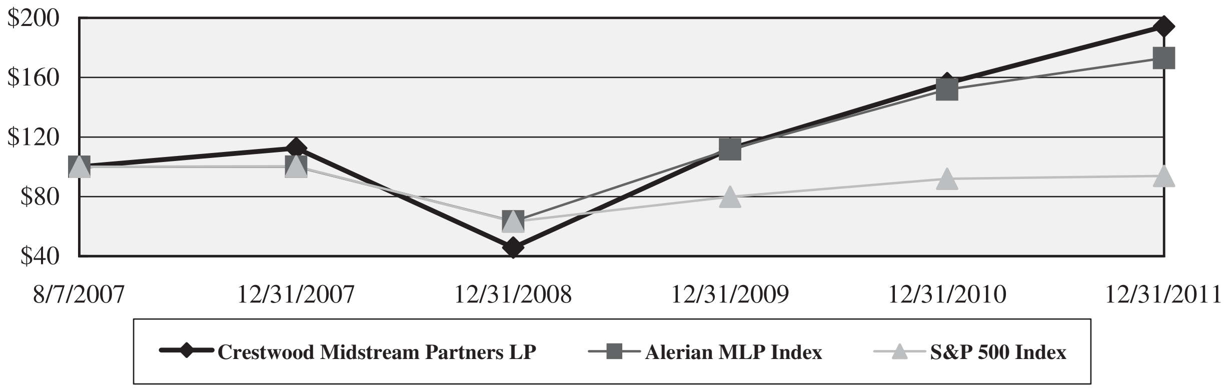
	Total Quarterly Distribution Per Unit	Marginal Percentage Interest in Distributions*	
	Target Amount	Unitholders	General Partner
Minimum Quarterly Distribution	$0.3000	98.26%	1.74%
First Target Distribution	up to $0.3450	98.26%	1.74%
Second Target Distribution	above $0.3450 up to $0.3750	85.26%	14.74%
Third Target Distribution	above $0.3750 up to $0.4500	75.26%	24.74%
Thereafter	above $0.4500	50.26%	49.74%

* Assuming there are no arrearages on common units and that our General Partner maintains its 1.74% general partner interest and continues to own the incentive distribution rights.

Performance Graph

The following performance graph compares the cumulative total unitholder return of our common units with the Standard & Poor's 500 Stock Index ("S&P 500") and the Alerian MLP Index for the period from our initial public offering (August 7, 2007) to December 31, 2011, assuming an initial investment of $100 and reinvestment of all subsequent distributions or dividends, as applicable.

Comparison of Cumulative Total Return



Item 6. Selected Financial Data

The information in this section should be read in conjunction with Part II, Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations", and Item 8, "Financial Statements and Supplementary Data". The preparation of our financial statements requires us to make a number of significant judgments and estimates, as well as consider a number of uncertainties. As such, the information reflected in the table below may not be indicative of our future results of operations or financial condition. Further detail on the judgments and estimates used in the preparation of the financial statements is included under "Critical Accounting Estimates" within Management's Discussion and Analysis of Financial Condition and Results of Operations. The following table includes selected financial data as of and for each of the five years in the period ended December 31, 2011 (In thousands, except per unit data and volume data).

	Year Ended December 31,				
	2011	2010 (1)	2009	2008	2007 (6)
Statement of Income Data:					
Revenues	$ 205,820	$113,590	$ 95,881	$ 76,084	$ 35,695
Operating income	73,871	47,872	43,408	37,151	13,182
Net income from continuing operations	45,003	34,872	34,491	28,472	8,848
Loss from discontinued operations	—	—	(1,992)	(2,330)	(592)
Net income	$ 45,003	$ 34,872	$ 32,499	$ 26,142	$ 8,256
Performance Measures:					
Diluted income per unit:					
From continuing operations per limited partner unit	$ 1.00	$ 1.03	$ 1.25	$ 1.03	$ 0.22
Net income per limited partner unit	$ 1.00	$ 1.03	$ 1.18	$ 0.95	$ 0.20
Distributions declared per unit (2)	$ 1.87	$ 1.66	$ 1.52	$ 1.39	$ 0.47
Volumes gathered (MMcf)	208,146	125,317	93,955	70,617	34,284
Volumes processed (MMcf)	52,613	46,660	54,386	56,225	30,802
Non-GAAP Performance Measures:					
EBITDA (3)	$ 107,683	$ 70,231	$ 64,238	$ 50,293	$ 21,120
Adjusted EBITDA (4)	109,962	76,549	64,238	50,293	21,120
Balance Sheet Data:					
Property, plant and equipment, net	$ 746,045	$531,371	$482,497	$441,863	$254,555
Total assets	1,026,892	570,627	487,624	502,606	278,410
Long-term debt	512,500	283,504	125,400	174,900	5,000
Other long-term obligations (5)	15,474	9,877	62,162	123,928	118,306
Partners' capital	455,623	258,753	284,837	115,208	110,200

(1) In January 2010, we acquired from Quicksilver certain midstream assets consisting of a gathering system and a compression facility, an amine treating facility and a dehydration facility in northern Tarrant and southern Denton Counties, Texas. We refer to these assets collectively as the "Alliance Assets" and the acquisition as the "Alliance Acquisition". Due to Quicksilver's control of CMLP through its ownership of the General Partner at the time of the Alliance Acquisition, the Alliance Acquisition is considered a transfer of net assets between entities under common control. As a result, CMLP was required to revise its financial statements to include the financial results and operations of the Alliance Assets. As such, the selected financial data gives retroactive effect to the Alliance Acquisition as if CMLP owned the Alliance Assets since August 8, 2008, the date on which Quicksilver acquired the Alliance Assets.

(2) Reported amounts include the fourth quarter distribution, which was paid in the first quarter of the subsequent year.

(3) Defined as net income plus income tax provision, interest expense, and depreciation, amortization and accretion expense (“EBITDA”). Additional information regarding EBITDA, including a reconciliation of EBITDA to Net Income as determined in accordance with GAAP, is included in Part II, Item 7, “Management’s Discussion and Analysis of Financial Condition and Results of Operations — Overview and Performance Metrics”.

(4) Defined as net income adjusted for interest expense, income taxes, depreciation expense, amortization expense, accretion expense and certain non-recurring expenses, including but not limited to items such as transaction related expenses including acquisition financing and transition services related expenses and gains/losses on the exchange of property, plant and equipment. Additional information regarding Adjusted EBITDA, including a reconciliation of Adjusted EBITDA to Net Income as determined in accordance with GAAP, is included in Part II, Item 7, “Management’s Discussion and Analysis of Financial Condition and Results of Operations — Overview and Performance Metrics”.

(5) Other long-term obligations include our capital leases and asset retirement obligations.

(6) Represents activity from August 7, 2007 to December 31, 2007.

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

The following is a discussion of our historical consolidated financial condition and results of operations that is intended to help the reader understand our business, results of operations and financial condition. Information contained herein does not include any impact of our recently announced Antero Acquisition. It should be read in conjunction with other sections of this report, including our historical consolidated financial statements and accompanying notes thereto included in Part II, Item 8, "Financial Statements and Supplementary Data," of this report.

This Management's Discussion and Analysis and Financial Condition and Results of Operations includes the following sections:

- *Overview and Performance Metrics*
- *Current Year Highlights*
- *Results of Operations*
- *Liquidity and Capital Resources*
- *Total Contractual Obligations*
- *Critical Accounting Estimates*

Overview and Performance Metrics

We are a growth-oriented publicly traded Delaware master limited partnership engaged in the gathering, processing, treating, compression, transportation and sales of natural gas and the delivery of NGLs produced from the geological formations of the Barnett Shale in north Texas, the Avalon Shale area of southeastern New Mexico, the Fayetteville Shale in northwestern Arkansas, the Granite Wash in the Texas Panhandle and the Haynesville/Bossier Shale in western Louisiana. We began operations in 2004 to provide midstream services primarily to Quicksilver as well as to other natural gas producers in the Barnett Shale. During 2011, Quicksilver accounted for 64% of our total consolidated revenue, including approximately 7% that is comprised of natural gas purchased by Quicksilver from Eni SpA and gathered under Quicksilver's Alliance System gathering agreement. For the years ended December 31, 2010 and 2009, Quicksilver accounted for 93% and 95%, respectively of our total consolidated revenue.

We conduct all of our operations in the midstream sector with three reportable operating segments. These operating segments reflect how we manage our operations and the primary geographic areas in which we operate. The operating segments consist of Barnett, Fayetteville and Granite Wash. Our operating segments are engaged in gathering, processing, treating, compression, transportation and sales natural of gas in the United States.

The results of our operations are significantly influenced by the volumes of natural gas gathered and processed through our systems. We gather, process, treat, compress, transport and sell natural gas pursuant to fee-based and percent-of-proceeds contracts. Under our fixed fee contracts, we do not take title to the natural gas or associated NGLs, and therefore, we avoid direct commodity price exposure. Under our percent-of-proceeds contracts, we take title to the residue gas, NGLs and condensate and remit a portion of the sale proceeds to the producer based on prevailing commodity prices.

Although we do not have significant direct commodity price exposure, lower natural gas prices could have a potential negative impact on the pace of drilling in dry gas areas such as areas in the Barnett Shale gathered by the Alliance and Lake Arlington Systems, the Fayetteville System and the Sabine System. We have two systems, (i) the Cowtown System, part of the Barnett segment, and (ii) the Granite Wash System that are located in basins that include NGL rich gas shale plays. In 2011 our systems located in NGL rich basins contributed approximately 53% of our total revenue. A prolonged decrease in the commodity price environment could result in our customers reducing their production volumes which would cause a resulting decrease in our revenue.

Our management uses a variety of financial and operational measures to analyze our performance. We view these measures as important factors affecting our profitability and unitholder value and therefore we review them monthly for consistency and to identify trends in our operations. These performance measures are outlined below:

Volume — We must continually obtain new supplies of natural gas to maintain or increase throughput volumes on our gathering and processing systems. We routinely monitor producer activity in the we serve to identify new supply opportunities. Our ability to achieve these objectives is impacted by:

- the level of successful drilling and production activity in areas where our systems are located;
- our ability to compete with other midstream companies for production volumes; and
- our pursuit of new acquisition opportunities.

Operating and Maintenance Expenses — We consider operating and maintenance expenses in evaluating the performance of our operations. These expenses are comprised primarily of labor, parts and materials, insurance, taxes, repair and maintenance costs, utilities and contract services. Our ability to manage operating and maintenance expenses has a significant impact on our profitability and ability to pay distributions.

EBITDA — We believe that EBITDA is a widely accepted financial indicator of a company's operational performance and its ability to incur and service debt, fund capital expenditures and make distributions. EBITDA is not a measure calculated in accordance with GAAP, as it does not include deductions for items such as depreciation, amortization and accretion, interest and income taxes, which are necessary to maintain our business. EBITDA should not be considered an alternative to net income, operating cash flow or any other measure of financial performance presented in accordance with GAAP. EBITDA calculations may vary among entities, so our computation may not be comparable to EBITDA measures of other entities. In evaluating EBITDA, we believe that investors should also consider, among other things, the amount by which EBITDA exceeds interest costs, how EBITDA compares to principal payments on debt and how EBITDA compares to capital expenditures for each period. A reconciliation of EBITDA to amounts reported under GAAP is presented below.

EBITDA is also used as a supplemental performance measure by our management and by readers of our financial statements such as investors, commercial banks, research analysts and others, to assess:

- financial performance of our assets without regard to financing methods, capital structure or historical cost basis;
- our operating performance as compared to those of other companies in the midstream energy industry, without regard to financing methods, capital structure or historical cost basis; and
- the viability of acquisitions and capital expenditure projects and the returns on investment opportunities.

Adjusted EBITDA — Adjusted EBITDA is used as a supplemental performance measure by our management and readers of our financial statements such as investors, commercial banks, research analysts and others. This performance metric is used to measure the financial performance of our assets, without regard to financing methods or capital structure, to generate cash sufficient to pay interest costs, support our indebtedness and make cash distributions and operating performance compared to other companies in the midstream industry. We define Adjusted EBITDA as net income adjusted for interest expense, income taxes, depreciation, amortization, and accretion expense and certain non-recurring expenses, including but not limited to items such as transaction related expenses and gains/losses on the exchange of property, plant and equipment. Adjusted EBITDA should not be considered as an alternative to net income, operating cash flow or any other measure of financial performance presented in accordance with GAAP. A reconciliation of Adjusted EBITDA to amounts reported under GAAP is presented below.

The following table reconciles Net Income to EBITDA and Adjusted EBITDA (In thousands):

	Year Ended December 31,		
	2011	2010	2009
Net income	$ 45,003	$34,872	$32,499
Add:			
Loss from discontinued operations	—	—	1,992
Interest expense [(1)]	27,617	13,550	8,519
Income tax provision (benefit)	1,251	(550)	399
Depreciation, amortization and accretion expense	33,812	22,359	20,829
EBITDA	$107,683	$70,231	$64,238
Non-recurring expenses [(2)]	2,279	6,318	—
Adjusted EBITDA	$109,962	$76,549	$64,238

(1) 2011 interest expense includes one-time financing cost of $2.5 million relating to the bridge loan associated with the Frontier Gas Acquisition.

(2) 2011 non-recurring expenses, includes transaction costs of $3.4 million and offset by a gain on exchange of property, plant and equipment of $1.1 million. For 2010, amount includes transaction costs of $2.7 million and $3.6 million of accelerated vesting expense related to equity based compensation resulting from the change-in-control in connection with the Crestwood Transaction.

Current Year Highlights

The following events took place during 2011 and have impacted or are likely to impact our financial condition and results of operations. The following should be read in conjunction with Part I, Item 1, "Business" of this report for a more detailed account of such events.

Operational and Industry Highlights

Shale gas production in the United States has grown rapidly in recent years as the natural gas industry has improved drilling and extraction methods while increasing exploration efforts. The United States has a wide distribution of shale formations containing vast resources of natural gas, NGLs and crude oil. Led by the rapid development of the Barnett Shale in Texas, shale gas activity has expanded into others areas such as the Marcellus, Fayetteville, and Haynesville/Bossier shale plays.

Our growth strategy during 2011 has focused on diversifying our geographic and customer profile through acquisitions. We have successfully expanded our operations beyond the Barnett Shale into other shale plays including Fayetteville Shale, the NGL rich Granite Wash region, Haynesville/Bossier Shale and the developing NGL rich Avalon Shale.

Volume Growth — Our operating results reflect our customers' efforts to exploit these shale plays. We gathered a total of 570 MMcfd in 2011 compared to 343 MMcfd in 2010, an increase of 66% year-over-year. Our gathering volumes in our existing Barnett operations have increased 130 MMcfd, from 343 MMcfd in 2010 to 473 MMcfd in 2011, an increase of 38% year-over-year. Additionally, our acquisitions completed during 2011 have contributed 97 MMcfd to the increase in gathered volumes. Our processing volumes increased from 128 MMcfd to 144 MMcfd, an increase of 12.5% year-over-year. The increase in processing volumes reflects the operations in NGL rich areas, including the Cowtown System in our Barnett segment and the Granite Wash System.

Distribution Growth — Our strong operating cash flows during 2011 as compared to 2010 have enabled us to raise our distribution to $0.49 per limited partner unit for the fourth quarter of 2011. This represents a 14% increase over the distribution for the fourth quarter of 2010 and our fifth consecutive quarterly increase.

Acquisitions

We have completed the following acquisitions during 2011:

- *Las Animas Acquisition* — On February 16, 2011, we completed the acquisition of certain midstream assets in the Avalon Shale play from a group of independent producers for $5.1 million.
- *Frontier Gas Acquisition* — On April 1, 2011, we completed the acquisition of certain midstream assets in the Fayetteville Shale and the Granite Wash plays from Frontier Gas Services, LLC for approximately $345 million.
- *Tristate Acquisition* — On November 1, 2011, we acquired Tristate from affiliates of Energy Spectrum Capital, Zwolle Pipeline, LLC and Tristate management for approximately $73 million which consisted of $65.0 million in cash plus a deferred payment of approximately $8.0 million one year following the closing date, subject to customary post-closing adjustments.

Financing Activities

Our financing activities during 2011 included:

- *Bridge Loan* — In February 2011, in connection with the Frontier Gas Acquisition, we obtained commitments from multiple lenders for a senior unsecured bridge loan in the aggregate amount of $200 million. On April 1, 2011, the commitment was not drawn and was terminated in connection with the closing of the Senior Notes described below. In the second quarter of 2011, we recognized $2.5 million of commitment fees, which is included in interest expense, related to the bridge loan.
- *Class C Units* — On April 1, 2011, we issued 6,243,000 Class C units, representing limited partner interests, in a private placement. The negotiated purchase price for the Class C units was $24.50 per unit, resulting in net proceeds to us of approximately $153 million which was used to finance a portion of the Frontier Gas Acquisition. In connection with the issuance of the Class C units, our General Partner made an additional capital contribution of $8.7 million to us in exchange for an additional 293,948 general partner units, increasing the General Partner interest to 2%.
- *Senior Notes* — On April 1, 2011, we issued $200 million of Senior Notes due April 2019. Our obligations under the Senior Notes are guaranteed on an unsecured basis by our current and future domestic subsidiaries. The proceeds were used to partially finance the Frontier Gas Acquisition. The Senior Notes accrue interest at a rate of 7.75% per annum, and are payable in cash semi-annually in arrears on April 1 and October 1 of each year, commencing on October 1, 2011.
- *Joinder Agreement to Credit Facility* — On April 1, 2011, we entered into an agreement with certain lenders under our Credit Facility, which expanded our borrowing capacity from $400 million to $500 million.
- *Equity Offering* — On May 4, 2011, we completed a public offering of 1,800,000 common units, representing limited partner interests in us, at a price of $30.65 per common unit ($29.75 per common unit, net of underwriting discounts and commissions), providing net proceeds of approximately $53 million. The net proceeds from the offering were used to reduce indebtedness under our Credit Facility and for general partnership purposes. In connection with the issuance of the common units, our General Partner did not make an additional capital contribution resulting in a reduction of our General Partner's general partner interest in us to approximately 1.9%.

Subsequent to December 31, 2011, we completed the following equity offering:

- *Equity Offering* — On January 13, 2012, we completed a public offering of 3,500,000 common units, representing limited partner interests in us, at a price of $30.73 per common unit ($29.50 per common unit, net of underwriting discounts), providing net proceeds of approximately $102.8 million. The net proceeds from the offering were used to reduce indebtedness under our Credit Facility. In connection with issuance of the common units, our General Partner did not make an additional capital contribution resulting in a reduction in our General Partner's general partner interest in us to approximately 1.74%.

Results of Operations

The following table summarizes our results of operations (In thousands):

	Year Ended December 31, 2011	2010	2009
Total revenues	$205,820	$113,590	$95,881
Operations and maintenance expense	36,303	25,702	21,968
Product purchases	38,787	—	—
General and administrative	24,153	17,657	9,676
Depreciation, amortization and accretion	33,812	22,359	20,829
Gain from exchange of property, plant and equipment	1,106	—	—
Operating income	73,871	47,872	43,408
Other income	—	—	1
Interest expense	27,617	13,550	8,519
Income tax provision (benefit)	1,251	(550)	399
Net income from continuing operations	45,003	34,872	34,491
Loss from discontinued operations	—	—	(1,992)
Net income	$ 45,003	$ 34,872	$32,499

The following table summarizes our gathering and processing volumes by segment (In MMcf):

	Year Ended December 31,					
	Gathering			Processing		
	2011	2010	2009	2011	2010	2009
Barnett	172,838	125,317	93,955	48,112	46,660	54,386
Fayetteville	23,421	—	—	—	—	—
Granite Wash	4,555	—	—	4,501	—	—
Other	7,332	—	—	—	—	—
Total	208,146	125,317	93,955	52,613	46,660	54,386

The following table summarizes our revenues by category by segment (In thousands):

	Year Ended December 31,											
	Gathering			Processing			Product Sales / Other			Total		
	2011	2010	2009	2011	2010	2009	2011	2010	2009	2011	2010	2009
Barnett	$108,705	$83,394	$59,903	$31,379	$30,196	$34,687	$ —	$—	$1,291	$140,084	$113,590	$95,881
Fayetteville	19,421	—	—	—	—	—	1,379	—	—	20,800	—	—
Granite Wash	346	—	—	133	—	—	37,734	—	—	38,213	—	—
Other	2,483	—	—	—	—	—	4,240	—	—	6,723	—	—
Total	$130,955	$83,394	$59,903	$31,512	$30,196	$34,687	$43,353	$—	$1,291	$205,820	$113,590	$95,881

The following table summarizes our operations and maintenance expense by segment (In thousands):

	Year Ended December 31, 2011	2010	2009
Barnett	$25,147	$25,702	$21,968
Fayetteville	8,992	—	—
Granite Wash	1,499	—	—
Other	665	—	—
Total	$36,303	$25,702	$21,968

2011 Compared with 2010

Total Revenue and *Volumes* — The increase in gathered volumes of 227 MMcfd and revenue of $92.2 million was due to an increase in the gathered volumes in Barnett, primarily the Alliance System. Also, we obtained additional volumes from the acquisition of the Fayetteville and Granite Wash Systems on April 1, 2011. The increase in Barnett gathered volumes of 130 MMcfd and revenue of $26.5 million primarily related to the Alliance System volumes that were the result of Quicksilver's drilling program pursuant to a joint development agreement with Eni SpA, which resulted in an increase of approximately 75 MMcfd in gathered volumes and $15.7 million in revenue. Fayetteville contributed 64 MMcfd of gathered volumes and $20.8 million in revenue. Granite Wash contributed 13 MMcfd of gathered volumes and $38.2 million in revenue primarily related to product sales under percent-of-proceeds contracts. The remaining increase in volumes of 20 MMcfd of gathered volumes and revenues of $6.7 million was related to the acquisition of the Las Animas and the Sabine Systems.

Operations and Maintenance Expense — The increase in operations and maintenance expense of $10.6 million was primarily related to acquisitions of the Fayetteville, Granite Wash, Las Animas and Sabine Systems. Barnett operations and maintenance expense decreased by $0.6 million compared to prior year as a result of reduced labor and lower facility operating costs despite higher gathered and processed volumes.

Product Purchases — The increase in product purchases of $38.8 million was due primarily to the cost of natural gas purchased from producers under percent-of-proceeds contracts, primarily related to Granite Wash.

General and Administrative Expense — The increase in general and administrative expense of $6.5 million reflected the transition from Quicksilver, which included increased personnel, new administrative systems and the increased scope of business operations as a result of our acquisitions during 2011. General and administration expense included approximately $3.4 million and $2.7 million for 2011 and 2010, respectively, in costs incurred for transaction related expenses. General and administrative expense also includes $0.9 million and $4.7 million of equity-based compensation expense for 2011 and 2010, respectively. Equity-based compensation expense in 2010 included $2.9 million from the acceleration of phantom units related to the change-in-control in connection with the Crestwood Transaction.

Gain from Exchange of Property, Plant and Equipment — The gain from exchange of property, plant and equipment in 2011 was due to an agreement with PVR Midstream, LLC to exchange the delivery of certain processing plants under contract with a third party resulting in proceeds of $5.9 million and a gain of $1.1 million. Our original plant was delivered to PVR Midstream, LLC during the third quarter of 2011, and our new plant is scheduled to be received by the second quarter of 2012.

EBITDA — EBITDA increased by $37.5 million primarily as a result of the increase in revenues described above. As a percentage of revenue, EBITDA decreased from 62% in 2010 to 52% in 2011. The increase in revenues and expenses includes product sales and product purchases primarily related to Granite Wash, which decreases EBITDA as a percent of revenue. Barnett's EBITDA increased from 77% to 82% of revenues from 2010 to 2011 primarily due to higher revenues offset by lower operating and maintenance expenses. The EBITDA for Fayetteville and Granite Wash was 51% and 9%, respectively, of revenue for the year ended 2011. See Part II, Item 8, "Financial Statements and Supplementary Data — Notes to the Financial Statements — Note 19 — Segment Information."

Adjusted EBITDA — Adjusted EBITDA increased by $33.4 million primarily as a result of the increase in revenues described above. As a percentage of revenue, Adjusted EBITDA decreased from 67% in 2010 to 53% in 2011. Adjusted EBITDA includes approximately $3.4 million and $2.7 million for 2011 and 2010, respectively, in costs incurred for transaction related expenses. The increase in revenues and expenses includes product sales and product purchases primarily related to Granite Wash, which decreases Adjusted EBITDA as a percent of revenue.

Depreciation, Amortization and Accretion Expense — Depreciation, amortization and accretion expense increased primarily as a result of the acquisition of the Fayetteville and Granite Wash Systems and the continuing expansion of our Barnett asset base. Fayetteville and Granite Wash contributed $6.9 million and $1.6 million, respectively, to depreciation, amortization and accretion expense.

Interest Expense — Interest expense increased primarily due to increased borrowings under our Credit Facility, which were principally used to fund capital projects and acquisitions, the addition of the Senior Notes and expenses related to the bridge loan commitment. These increases were partially offset by the termination of the subordinated note in October 2010.

The following table provides a summary of interest (In thousands):

	Year Ended December 31, 2011	Year Ended December 31, 2010
Interest cost:		
Credit Facility	$12,971	$11,532
Senior Notes	12,166	—
Bridge Loan	2,500	—
Capital lease interest	179	—
Subordinated note	—	2,018
Total cost	27,816	13,550
Less capitalized interest	(199)	—
Interest expense	$27,617	$13,550

2010 Compared with 2009

Total Revenues and *Volumes* — The increase in revenues and volumes was related to the Barnett operations. The increase in revenue of $17.7 million was due to an increase in the gathered volumes of natural gas on the Alliance System and Lake Arlington System. The increase in the Alliance System volumes was the result of Quicksilver's drilling program in the area, under a joint development agreement with Eni SpA, which resulted in an increase of approximately 100 MMcfd in gathered volumes and $23.4 million in revenue. The increase of 11 MMcfd of volumes on the Lake Arlington System was the result of additional well connects by producers resulting in a $2.4 million increase in revenue. These increases were offset by approximately $6.8 million due to the natural decline rate from existing wells connected to the Cowtown processing facility as local producers focused on new well connections in the Alliance and Lake Arlington areas.

Operations and Maintenance Expense — The increase in operations and maintenance expense was due to $3.7 million of higher expenses attributable to the operation of the Alliance System. Operating expenses also increased due to $0.9 million in equity compensation expense recognized in the fourth quarter of 2010 as a result of the change-in-control related to the Crestwood Transaction.

General and Administrative Expense — The increase in general and administrative expense was due to $2.9 million of equity compensation expense, as a result of additional phantom unit grants issued in January 2010 and the vesting of equity-based compensation resulting from the change-in-control in connection with the Crestwood Transaction. General and administrative expense includes $4.7 million, which includes the $2.9 million of equity vesting expense, and $1.8 million of equity-based compensation expense for 2010 and 2009, respectively. General and administration expense also includes approximately $2.7 million in costs incurred to transition systems and administrative functions related to the Crestwood Transaction. Excluding these non-recurring expenses, general and administrative expenses increased $0.6 million due primarily to increased compensation and benefits expense and costs of a new corporate location.

EBITDA — EBITDA increased primarily as a result of the increase in revenues described above. As a percentage of revenue, adjusted gross margin and EBITDA decreased from 67% in 2009 to 62% in 2010, primarily due to the increase in revenues and was partially offset by higher operations and maintenance expense associated with our current scale of operations and higher general and administrative expense. See Part II, Item 8, "Financial Statements and Supplementary Data — Notes to the Financial Statements — Note 19 — Segment Information."

Adjusted EBITDA — Adjusted EBITDA increased by $12.3 million primarily as a result of the increase in revenues described above. As a percentage of revenue, Adjusted EBITDA remained constant at approximately 67% from 2009 to 2010. Year over year, revenues increased proportionally to increases in operations and maintenance expense, interest expense, and general and administrative expense.

Depreciation, Amortization and Accretion Expense — Depreciation, amortization and accretion expense increased primarily as a result of continuing expansion of our asset base, which included the expansion of the Alliance System.

Interest Expense — Interest expense increased primarily due to increases in the credit facility borrowings, principally used to fund capital projects, partially offset by the absence of any liability related to repurchase obligations. As a result of the termination of our previous credit facility, we recognized $1.6 million in interest expense to write-off our remaining deferred financing costs. The increase was offset by the termination of our repurchase obligations of the Hill County Dry System ("HCDS"), during 2009 for which we had no interest expense in 2010. During December 2009, we completed a public equity offering and used $80.5 million of net proceeds to pay down our previous credit facility that terminated with the Crestwood Transaction. During January 2010, we re-borrowed approximately $95 million to purchase the Alliance Assets and repaid $11 million upon the underwriters' exercise of their over-allotment.

The following table provides a summary of interest expense (In thousands):

	Year Ended December 31,	
	2010	**2009**
Interest cost:		
Credit Facility	$11,532	$5,076
Repurchase obligations	—	1,681
Subordinated note	2,018	2,072
Total cost	13,550	8,829
Less capitalized interest	—	(310)
Interest expense	$13,550	$8,519

Liquidity and Capital Resources

Our sources of liquidity include cash flows generated from operations, available borrowing capacity under our Credit Facility, and issuances of additional debt and equity in the capital markets. We believe that our sources of liquidity will be sufficient to fund our short-term working capital requirements, capital expenditures and quarterly cash distributions during 2012. The amount of distributions to unitholders is determined by the board of directors of our General Partner on a quarterly basis.

We regularly review opportunities for both greenfield growth projects and acquisitions that will enhance our financial performance. Since we distribute most of our available cash to our unitholders, we depend on a combination of borrowings under our Credit Facility, debt or equity offerings to finance the majority of our long-term growth capital expenditures or acquisitions.

Management continuously monitors our leverage position and our anticipated capital expenditures relative to our expected cash flows. We continue to evaluate funding alternatives, including additional borrowings and the issuance of debt or equity securities, to secure funds as needed or refinance outstanding debt balances with longer-term notes.

Shelf Registration

On April 28, 2011, a registration statement (No. 333-171735) providing for the issuance of up to $500 million of our common units, senior units, debt securities, warrants, purchase contracts or units was declared effective by the SEC. During 2011, we issued 1,800,000 of our common units in a public offering at a price of $30.65 per common unit. At December 31, 2011, the registration statement had remaining capacity allowing for the issuance of up to approximately $444.8 million of securities. After the January 2012 public offering of 3,500,000 common units at a price per unit of $30.73, the registration statement had remaining capacity allowing for the issuance of up to approximately $337.2 million of securities.

Known Trends and Uncertainties Impacting Liquidity

Our financial condition and results of operations, including our liquidity and profitability, can be significantly affected by the following:

- ***Concentration of Gathering Revenues from Quicksilver:*** During 2011, Quicksilver accounted for 64% of our total consolidated revenue, including approximately 7% that is comprised of natural gas purchased by Quicksilver from Eni SpA and gathered under Quicksilver's Alliance System gathering agreement. For the years ended December 31, 2010 and 2009, Quicksilver accounted for 93% and 95%, respectively of our total consolidated revenue. While we have reduced our dependency upon Quicksilver during 2011 through the acquisition of additional midstream assets including long term contracts with creditworthy producers such as BHP, BP, ExxonMobil and Chesapeake, we remain dependent upon Quicksilver for a substantial percentage of our current business. The risk of revenue fluctuations in the near term is mitigated by the use of fixed-fee contracts for providing gathering, processing, treating and compression services; however, we are still susceptible to volume fluctuations. While our acquisitions reduce the concentration of risk associated with our dependency on one producer and one geographic area, we continue to regularly review opportunities for both greenfield growth projects and acquisitions in other producing basins and with other producers in the future.
- ***Access to Capital Markets:*** During 2011, we raised approximately $500 million through debt and equity offering and increases to our Credit Facility to fund acquisitions and growth capital projects. In January 2012, an additional $102.8 was raised through the public issuance of common units. While we anticipate that our currently available borrowing capacity under our Credit Facility is sufficient to fund our planned level of growth capital spending in 2012, additional debt and equity offerings would be necessary to fund additional acquisitions or other growth capital projects.
- ***Natural Gas Prices:*** Adding new volumes through our gathering systems is dependent on the drilling and completion activities of natural gas producers in the area of our operations. Although investment returns differ between natural gas basins, rich gas and dry gas reservoirs in certain natural gas basins and between various production companies, low natural gas prices may reduce the levels of drilling activity in areas around certain of our assets, particularly those that concentrate on gathering from dry gas reservoirs or are located in dry gas basins. We seek to mitigate this risk by diversifying into various geographical production basins including a distinction between natural gas produced from rich gas reservoirs in the basins we operate as compared to natural gas produced from dry gas reservoirs in the basins we operate. We have observed that largely due to increased prices for crude oil and NGLs, producers are shifting their drilling and development plans to focus on increasing production from rich gas basins or shale plays which offer better drilling economics as compared to production from dry gas basins. We have two systems located in basins that include NGL rich gas shale plays, (i) the Cowtown

System, part of the Barnett segment and, (ii) the Granite Wash System. For the year ended December 31, 2011, these rich gas systems accounted for approximately 53% of our total revenues. We will continue to focus on expanding our business activities and opportunities in rich gas basins or rich gas shale plays due to the current trend of increased drilling and producer activities in these areas.

- ***Regulatory Requirements:*** Our operations and the operations of our customers are subject to a number of federal, state, local and other laws and regulations. If additional regulations and permits are adopted, it could impact the timing and cost of capital projects and operations and drilling activities of our customers. For example, regulation of hydraulic fracturing techniques used by our customers is primarily conducted at the state level through permitting and other compliance requirements. If proposed federal legislation is adopted, it could establish an additional level of regulation and permitting. Any changes in statutory regulations or delays in the issuance of required permits may impact the throughput on our systems.
- ***Impact of Inflation and Interest Rates:*** Although inflation in the U.S. has been relatively low in recent years, the U.S. economy may experience a significant inflationary effect in the future. Although inflation would negatively impact the cost of our operations and cash flows through services provided to us, the majority of our gathering and processing agreements allow us to charge increased rates based on indices expected to track such inflationary trends. Interest rates have also stayed low in recent years, as compared with historical averages. Should interest rates rise, our financing costs would increase accordingly. In addition, as with other yield-oriented securities, our unit price would also be negatively impacted by higher interest rates. Higher interest rates would increase the costs of issuing debt or equity necessary to finance potential future acquisitions. However, our competitors would face similar circumstances and we expect our cost of capital to remain competitive.

Cash Flows

The following table provides a summary of our cash flows by category (In thousands):

	Year Ended December 31,		
	2011	**2010**	**2009**
Net cash provided by operating activities	$ 86,331	$ 48,003	$ 68,949
Net cash used in investing activities	(456,535)	(149,345)	(54,818)
Net cash provided by (used in) financing activities	370,999	100,598	(13,688)

Operating Activities

2011 Compared to 2010 — The increase in cash flows provided by operating activities is the result of an increase in operating income as a result of the Frontier Gas and Tristate Acquisitions and improved performance by our Barnett operations. The increase also reflects an increase in accounts payable and accrued expenses related to operations, ad valorem tax and interest expense, partially offset by higher receivables from the Fayetteville and Granite Wash operations and the gain on exchange of property, plant and equipment.

2010 Compared to 2009 — The decrease in cash flows from operating activities resulted from an increase in the accounts receivable balance primarily related to the timing of collections from Quicksilver.

Investing Activities

The midstream energy business is capital intensive, requiring significant investment for the acquisition or development of new facilities. We categorize our capital expenditures as either:

- expansion capital expenditures, which are made to construct additional assets, expand and upgrade existing systems, or acquire additional assets; or
- maintenance capital expenditures, which are made to replace partially or fully depreciated assets, to maintain the existing operating capacity of our assets and extend their useful lives.

Since our initial public offering in August 2007, we have made substantial capital expenditures. We anticipate that we will continue to make capital expenditures to develop our gathering and processing assets in the producing basins in which we operate as well as opportunities to expand into new geographical areas through acquisitions and greenfield growth opportunities.

In 2012 we expect to spend between $35 million and $40 million on capital projects, of which approximately $7 to $8 million is expected to be classified as maintenance capital expenditures. We anticipate that the expansion capital expenditures in 2012 will expand our gathering systems through additional pipelines to connect to new wells, purchase additional compression and treating equipment and generally increase the capacity of our systems in each of our operating segments. We expect to fund our capital expenditures through borrowings under our Credit Facility and cash generated from operations.

2011 Compared to 2010 — Investing activities increased approximately $307 million. This increase directly relates to $414.1 million of assets acquired in 2011. This increase was offset by lower capital expenditures compared to 2010 and proceeds from the exchange of assets with PVR Midstream, LLC.

2010 Compared to 2009 — The increase in cash flows used in investing activities resulted from the distribution to Quicksilver of $80.3 million related to the purchase of the Alliance Assets. Additionally, for the 2010 period, we spent $69 million for gathering assets and facilities, of which approximately $50 million related to the expansion of the Alliance System.

Financing Activities

2011 Compared to 2010 — Changes in cash flows provided by financing activities during the 2011 period resulted primarily from net borrowings under our Credit Facility of $29 million, $200 million net proceeds received from the issuance of our Senior Notes in April 2011, $153 million in net proceeds from the issuance of 6,243,000 Class C units in April 2011 and $53 million in net proceeds from the issuance of 1,800,000 common units in May 2011. The increase in cash flows provided by financing activities was offset primarily by $64 million in quarterly distributions to unitholders, which increased $14 million from 2010.

2010 Compared to 2009 — Changes in cash flows provided by financing activities during the 2010 period resulted primarily from net borrowings under our Credit Facility of $158.1 million, compared with the 2009 period pay down under our old credit facility of $49.5 million. This change is largely reflective of our funding of the purchase of the Alliance System for $84.4 million. We also borrowed $13.6 million to pay financing costs related to our Credit Facility. In addition, we distributed $12.8 million more to our unitholders during the 2010 period due to increases in our quarterly distributions from December 31, 2009 to December 31, 2010. In January 2010, the underwriters of our public equity offering exercised their option to purchase an additional 549,200 common units, which generated proceeds of $11.1 million compared to $80.8 million in 2009.

Repurchase Obligation to Quicksilver

During 2009, the independent directors of our General Partner voted to acquire certain Cowtown System assets subject to the repurchase obligation that had an original cost of approximately $5.6 million. We paid $5.6 million for these assets in September 2009. Furthermore, the independent directors of our General Partner elected not to acquire certain Cowtown System assets that had been previously included in the repurchase obligation. In doing so, we derecognized assets with a carrying value of $56.8 million and also derecognized liabilities associated with the repurchase of $68.6 million. The difference of $11.8 million between the assets' carrying values and their repurchase obligation was reflected as an increase in partners' capital effective upon the decision not to purchase. We also entered into an agreement with Quicksilver to permit us to gather third party gas for a fee across the Cowtown System pipeline laterals retained by Quicksilver. The decision not to acquire certain Cowtown System assets did not have a material effect on our gathering and processing revenues as the natural gas stream from these laterals continues to flow into our Cowtown System gathering and processing facilities.

We had been obligated to repurchase from Quicksilver a gas gathering system in Hill County, Texas, at its fair market value within two years after its completion and commencement of commercial service. As a result of this contractual purchase obligation, we have historically included the HCDS in our financial statements since our initial public offering. In November 2009, we and Quicksilver mutually agreed to waive both parties' rights and obligations to transfer ownership of the HCDS to us. The revenues and expenses directly attributable to the HCDS for the periods prior to November 2009 have been retroactively reported as discontinued operations. For a complete description of our transactions with Quicksilver, see Part II, Item 8, "Financial Statements and Supplementary Data — Notes to the Financial Statements" — Note 5 — "Discontinued Operations" and Note 16 — "Transactions with Related Parties".

Long-Term Debt

For a complete description of Long-Term Debt, see Part II, Item 8, "Financial Statements and Supplementary Data — Notes to the Financial Statements — Note 10 — Long-Term Debt".

Total Contractual Obligations

The following table summarizes our total contractual obligations as of December 31, 2011 (In thousands):

	Payments Due by Period						
Contractual Obligations	**Total**	**2012**	**2013**	**2014**	**2015**	**2016**	**Thereafter**
Long-term debt (1)	$512,500	$ —	$ —	$ —	$ —	$312,500	$200,000
Scheduled interest obligations (2) (3)	150,929	25,781	25,781	25,781	23,211	15,500	34,875
Operating lease obligations (4)	4,885	2,538	1,068	625	433	13	208
Capital lease obligations (5)	6,882	2,860	2,860	1,162	—	—	—
Asset retirement obligations (6)	11,545	—	—	—	—	—	11,545
Total contractual obligations	$686,741	$31,179	$29,709	$27,568	$23,644	$328,013	$246,628

(1) As of December 31, 2011, we had $312.5 million outstanding under our Credit Facility and $200 million of Senior Notes.

(2) We estimate interest payments to be approximately $15.5 million annually on our Senior Notes.

(3) Based on our debt outstanding and interest rates in effect at December 31, 2011, we estimate interest payments to be approximately $10.3 million annually on our Credit Facility. For each additional $10 million in borrowings, annual interest payments will increase by approximately $0.3 million. If the committed amount under our Credit Facility would have been fully utilized at year-end 2011 at interest rates in effect at December 31, 2011, annual interest expense would increase by approximately $6.2 million. If interest rates on our December 31, 2011 variable debt balance of $312.5 million increase or decrease by one percentage point, our annual income will decrease or increase by $3.1 million related to interest expense.

(4) We lease compressors, office buildings, automobiles and other property under operating leases.

(5) We acquired compressor leases accounted for as capital leases through the Frontier Gas Acquisition on April 1, 2011. Amounts reflect our obligations under those capital leases.

(6) For more information regarding our asset retirement obligations, see Part II, Item 8, "Financial Statements and Supplementary Data — Notes to the Financial Statements — Note 11 — Asset Retirement Obligations", none of which is expected to be due before 2016.

Critical Accounting Estimates

Management discusses with our Audit Committee the development, selection and disclosure of our critical accounting policies and estimates and the application of these policies and estimates. Our consolidated financial statements are prepared in accordance with GAAP in the United States. We believe our accounting policies are appropriately selected and applied.

Use of Estimates

GAAP requires management to make estimates and judgments that affect the amounts reported in the financial statements and notes. These estimates and judgments are based on information available at the time we make such estimates and judgments and principally affect the reported amounts of depreciation expense, asset retirement obligations, impairment of long-lived assets and goodwill impairment.

Depreciation Expense and Cost Capitalization Policies

Policy Description

Our assets consist primarily of natural gas gathering pipelines, compression facilities and processing plants. We capitalize all construction-related direct labor and material costs plus the interest cost associated with financing the construction of new facilities. These aggregate costs less the estimated salvage value are then depreciated using the straight-line method over the estimated useful life of the constructed asset. The costs of renewals and betterments that extend the useful life or substantially improve the efficiency of property, plant and equipment are also capitalized. The costs of repairs, replacements and normal maintenance projects are expensed as incurred.

Judgments and Assumptions

The computation of depreciation expense requires judgment regarding the estimated useful lives and salvage value of assets. As circumstances warrant, depreciation estimates are reviewed to determine if any changes are needed. Such changes could involve an increase or decrease in estimated useful lives or salvage values which could impact current and future depreciation expense. When making expenditures, we also must determine whether they improve efficiency or extend the useful life of the underlying assets, to determine whether to capitalize such amounts paid.

Asset Retirement Obligations

Policy Description

In certain instances, we have obligations to remove equipment and restore land at the end of our right-of-way period or the asset's useful life. We estimate the amount and timing of asset retirement expenditures and record the discounted fair value of asset retirement obligations as a liability in the period in which it is legally or contractually incurred. Upon initial recognition of the asset retirement liability, an asset retirement cost is capitalized by increasing the carrying amount of the related long-lived asset by the same amount as the liability. Changes in the liability for the asset retirement obligation are recognized for both the passage of time and revisions to either the timing or the amount of the estimated cash flows. In periods subsequent to initial measurement, the asset retirement cost is allocated to expense on a straight-line basis over the asset's useful life, and the liability is accreted over the life of the obligation.

Judgments and Assumptions

Inherent in the fair value calculation of asset retirement obligations are numerous assumptions and judgments including the estimated remaining lives of the wells connected to our systems, the estimated cost to remove equipment or restore land in the future, inflation factors and credit adjusted discount rates. To the extent future revisions to these assumptions impact the fair value of our existing asset retirement obligation, a corresponding adjustment is made to our liability.

Impairment of Long-Lived Assets

Policy Description

Property, plant and equipment are generally reported at the lower of historical cost less accumulated depreciation or fair value. Assets acquired through acquisitions are recorded at fair value. Long-lived assets are reviewed for impairment whenever events or circumstances indicate that the carrying amount of an asset may not be recoverable. If we were to determine that an asset's estimated future cash flows will not be sufficient to recover its carrying amount, we would record an impairment charge to reduce the carrying amount for the asset to its estimated fair value. Any impairment is measured as the excess of the carrying amount over its estimated fair value.

Judgment and Assumptions

Management evaluates changes within our business that would indicate that the carrying amount of an asset is higher than its fair value. Such evaluation requires application of judgment surrounding useful lives, long-range revenue and expense estimates and economic conditions as well as others factors to determine the total future net cash flows of each asset. The amount of impairment recorded, if any, is contingent on management's determination of the fair value of the assets based on estimated future cash flows.

Goodwill Impairment

Policy Description

Goodwill represents the fair value above the net identifiable assets acquired in a business combination. We evaluate goodwill for impairment annually on December 31, and whenever events or changes indicate that it is more likely than not that the fair value of a reporting unit is less than its carrying amount. Accounting standards require a two-step test where the first step compares the fair value of the reporting unit to its carrying value, including goodwill and must be tested at the reporting unit level. We have three operating segments with five reporting units.

The first step compares the fair value of the reporting unit to its carrying value, including goodwill. If the fair value exceeds the carry amount, goodwill of the reporting unit is not considered impaired. If however, the fair value does not exceed the carrying amount the second step compares the implied fair value to the carrying value of the reporting unit. If the carrying amount of a reporting unit's goodwill exceeds the implied fair value of that goodwill, the excess of the carrying value over the implied value is recognized as an impairment loss.

Judgment and Assumptions

Management must apply judgment to determine the fair value of a reporting unit. As quoted prices for the reporting units are not readily available, management uses an income approach in accordance with Accounting Standards Codification Topic 820, *Fair Value Measurements*, to determine the estimated fair value of the reporting units. Under the income approach, the fair value of the reporting unit is estimated based on the present value of future cash flows. The income approach is dependent on a number of factors including estimates of forecasted revenues and expenses, appropriate discount rates to calculate a market derived fair value. Inherent to this analysis, management made multiple assumptions around the market inputs. As a result of the goodwill impairment testing at December 31, 2011, the reporting units with allocated goodwill did not fail step one of the impairment test. As such, no goodwill impairment has been identified for fiscal year 2011.

Off-Balance Sheet Arrangements

We have no off-balance sheet arrangements within the meaning of Item 303(a)(4) of Regulation S-K.

Recently Issued Accounting Pronouncements

The information regarding recent accounting pronouncements is included in Part II, Item 8, "Financial Statements and Supplementary Data — Notes to the Financial Statements — Note 2 — Summary of Significant Accounting Policies" to this report.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

We have established policies and procedures for managing risk within our organization, including internal controls. The level of risk assumed by us is based on our objectives and capacity to manage risk.

Credit Risk

Our primary credit risk relates to our dependency on Quicksilver for a significant portion of our revenues, which causes us to be subject to the risk of nonpayment or late payment by Quicksilver. Quicksilver's credit ratings are below investment grade, where they may remain for the foreseeable future. Accordingly, this risk could be higher than it might be with a more creditworthy customer or with a more diversified group of customers. As our largest customer, we remain dependent upon Quicksilver for a substantial percentage of our revenues and unless and until we further diversify our customer base further, we expect to continue to be subject to non-diversified risk of nonpayment or late payment of our fees. However, our dependency on Quicksilver and the resulting credit risk has been reduced from prior periods through the acquisition of additional midstream assets, primarily through the Frontier Gas and Tristate Acquisitions, including long term contracts with investment grade customers such as BHP, BP, ExxonMobil, Devon and Enterprise Products and creditworthy producers such as Chesapeake. Additionally, we perform credit analyses of our customers on a regular basis pursuant to our corporate credit policy. We have not had any significant losses due to counter-party failures to perform.

Interest Rate Risk

Although our base interest rates remain low, our leverage ratios directly influence the spreads charged by lenders. The credit markets could also drive the spreads charged by lenders upward. As base rates or spreads increase, our financing costs will increase accordingly. Although this could limit our ability to raise funds in the capital markets, we expect that our competitors would face similar challenges with respect to funding acquisitions and capital projects. We are exposed to variable interest rate risk as a result of borrowings under our Credit Facility. The table of contractual obligations contained in Item 7 of this report contains more information regarding interest rate sensitivity.

Item 8. Financial Statements and Supplementary Data

CRESTWOOD MIDSTREAM PARTNERS LP
INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Unitholders of
Crestwood Midstream Partners LP

We have audited the accompanying consolidated balance sheets of Crestwood Midstream Partners LP and subsidiaries (the "Partnership") as of December 31, 2011 and 2010, and the related consolidated statements of income, cash flows, and changes in partners' capital for each of the three years in the period ended December 31, 2011. These financial statements are the responsibility of the Partnership'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, such consolidated financial statements present fairly, in all material respects, the financial position of Crestwood Midstream Partners LP and subsidiaries at December 31, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Partnership's internal control over financial reporting as of December 31, 2011, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 29, 2012, expressed an unqualified opinion on the Partnership's internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas

February 29, 2012

CRESTWOOD MIDSTREAM PARTNERS LP
CONSOLIDATED STATEMENTS OF INCOME
(In thousands, except for per unit data)

	Year Ended December 31,		
	2011	2010	2009
Revenue			
Gathering revenue - related party	$102,427	$ 77,645	$57,593
Gathering revenue	28,528	5,749	2,310
Processing revenue - related party	28,798	27,590	32,605
Processing revenue	2,714	2,606	2,082
Other revenue - related party	—	—	1,291
Product sales	43,353	—	—
Total revenue	205,820	113,590	95,881
Expenses			
Operations and maintenance	36,303	25,702	21,968
Product purchases	38,787	—	—
General and administrative	24,153	17,657	9,676
Depreciation, amortization and accretion	33,812	22,359	20,829
Total expenses	133,055	65,718	52,473
Gain from exchange of property, plant and equipment	1,106	—	—
Operating income	73,871	47,872	43,408
Other income	—	—	1
Interest expense	27,617	13,550	8,519
Income from continuing operations before income taxes	46,254	34,322	34,890
Income tax provision (benefit)	1,251	(550)	399
Net income from continuing operations	45,003	34,872	34,491
Loss from discontinued operations	—	—	(1,992)
Net income	$ 45,003	$ 34,872	$32,499
General partner's interest in net income	$ 7,735	$ 2,526	$ 1,172
Limited partners' interest in net income	$ 37,268	$ 32,346	$31,327
Basic income (loss) per unit:			
From continuing operations per limited partner unit	$ 1.00	$ 1.11	$ 1.38
From discontinued operations per limited partner unit	—	—	(0.08)
Net income per limited partner unit	$ 1.00	$ 1.11	$ 1.30
Diluted income (loss) per unit:			
From continuing operations per limited partner unit	$ 1.00	$ 1.03	$ 1.25
From discontinued operations per limited partner unit	—	—	(0.07)
Net income per limited partner unit	$ 1.00	$ 1.03	$ 1.18
Weighted-average number of limited partner units:			
Basic	37,206	29,070	24,057
Diluted	37,320	31,316	28,189
Distributions declared per limited partner unit (attributable to the period ended)	$ 1.87	$ 1.66	$ 1.52

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

CRESTWOOD MIDSTREAM PARTNERS LP
CONSOLIDATED BALANCE SHEETS
(In thousands, except for unit data)

	December 31, 2011	December 31, 2010
ASSETS		
Current assets		
Cash and cash equivalents	$ 797	$ 2
Accounts receivable	11,926	1,679
Accounts receivable - related party	27,312	23,003
Prepaid expenses and other	1,935	1,052
Total current assets	41,970	25,736
Property, plant and equipment, net	746,045	531,371
Intangible assets, net	127,760	—
Goodwill	93,628	—
Deferred financing costs, net	16,699	12,890
Other assets	790	630
Total assets	$1,026,892	$570,627
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities		
Accounts payable, accrued expenses and other	$ 31,794	$ 2,917
Accrued additions to property, plant and equipment	7,500	11,309
Accounts payable - related party	1,308	4,267
Capital leases	2,693	—
Total current liabilities	43,295	18,493
Long-term debt	512,500	283,504
Long-term capital leases	3,929	—
Asset retirement obligations	11,545	9,877
Commitments and contingent liabilities (Note 13)		
Partners' capital		
Common unitholders (32,997,696 and 31,187,696 units issued and outstanding at December 31, 2011 and December 31, 2010, respectively)	286,945	258,069
Class C unitholders (6,596,635 and 0 units issued and outstanding at December 31, 2011 and December 31, 2010, respectively)	157,386	—
General partner	11,292	684
Total partners' capital	455,623	258,753
	$1,026,892	$570,627

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

CRESTWOOD MIDSTREAM PARTNERS LP
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)

	Year Ended December 31,		
	2011	2010	2009
Operating activities:			
Net income	$ 45,003	$ 34,872	$ 32,499
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	33,304	21,848	23,046
Accretion of asset retirement obligations	508	511	394
Deferred income taxes	—	(768)	399
Equity-based compensation	916	5,522	1,705
Deferred financing fees, debt issuance costs and other	3,473	4,961	6,191
Gain from exchange of property, plant and equipment	(1,106)	—	—
Changes in assets and liabilities:			
Accounts receivable	(7,348)	(270)	740
Prepaid expenses and other	249	(903)	387
Accounts receivable - related party	(4,309)	(23,003)	3,621
Accounts payable - related party	(2,959)	4,630	—
Accounts payable, accrued expenses and other	18,600	603	(33)
Net cash provided by operating activities	86,331	48,003	68,949
Investing activities:			
Capital expenditures	(48,405)	(69,069)	(54,818)
Proceeds from exchange of property, plant and equipment	5,943	—	—
Frontier Gas Acquisition, net of cash acquired	(344,562)	—	—
Las Animas Acquisition, net of cash acquired	(5,100)	—	—
Tristate Acquisition, net of cash acquired	(64,411)	—	—
Distributions to Quicksilver for Alliance Assets	—	(80,276)	—
Net cash (used in) investing activities	(456,535)	(149,345)	(54,818)
Financing activities:			
Proceeds from issuance of senior notes	200,000	—	—
Proceeds from credit facility	215,200	426,704	56,000
Repayments of credit facility	(186,204)	(268,600)	(105,500)
Payments on capital leases	(1,966)	—	—
Debt issuance costs paid	(6,982)	(13,568)	(1,446)
Proceeds from issuance of Class C units, net	152,671	—	—
Repayment of repurchase obligation to Quicksilver	—	—	(5,645)
Proceeds from issuance of common units, net	53,550	11,054	80,729
Distribution to Quicksilver	—	—	(816)
Contributions by partners	8,741	—	—
Distributions to partners	(64,011)	(49,699)	(36,947)
Taxes paid for equity-based compensation vesting	—	(5,293)	(63)
Net cash provided by (used in) financing activities	370,999	100,598	(13,688)
Net cash increase (decrease)	795	(744)	443
Cash and cash equivalents at beginning of period	2	746	303
Cash and cash equivalents at end of period	$ 797	$ 2	$ 746
Cash paid for interest (net of amounts capitalized)	$ 20,281	$ 8,590	$ 4,682
Non-cash transactions:			
Working capital related to capital expenditures	$ 7,500	$ 11,309	$ 10,105
Costs in connection with the equity offering	—	—	(416)
Contribution of property, plant and equipment from Quicksilver	—	—	72,342
Disposition of property, plant and equipment under repurchase obligations, net	—	—	111,070
Contribution related to assets not purchased pursuant to repurchase obligations	—	—	20,663
Repayment of subordinated note	—	57,736	—
Paid-In-Kind value to Class C unitholders	9,511	—	—
Deferred payment on Tristate Acquisition	8,000	—	—

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

CRESTWOOD MIDSTREAM PARTNERS LP
CONSOLIDATED STATEMENTS OF CHANGES IN PARTNERS' CAPITAL
(In thousands)

	Partners' Capital				
	Limited Partners				
	Common	Subordinated Unitholders	Class C Unitholders	General Partner	Total
Balance at December 31, 2008	$117,541	$ (2,328)	$ —	$ (5)	$115,208
Equity-based compensation	1,705	—	—	—	1,705
Distributions paid	(18,471)	(17,270)	—	(1,206)	(36,947)
Net income	18,384	12,926	—	1,189	32,499
Contribution by Quicksilver	81,830	9,712	—	580	92,122
Issuance of units, net of offering costs	80,313	—	—	—	80,313
Taxes paid for equity-based compensation vesting	(63)	—	—	—	(63)
Balance at December 31, 2009	$281,239	$ 3,040	$ —	$ 558	$284,837
Equity-based compensation	5,522	—	—	—	5,522
Distributions paid	(28,648)	(18,651)	—	(2,400)	(49,699)
Distribution to Quicksilver	(80,276)	—	—	—	(80,276)
Net income	22,614	9,732	—	2,526	34,872
Issuance of units, net of offering costs	11,054	—	—	—	11,054
Conversion of subordinated note payable	57,736	—	—	—	57,736
Conversion of subordinated units	(5,879)	5,879	—	—	—
Taxes paid for equity-based compensation vesting	(5,293)	—	—	—	(5,293)
Balance at December 31, 2010	$258,069	$ —	$ —	$ 684	$258,753
Equity-based compensation	916	—	—	—	916
Distributions paid	(58,143)	—	—	(5,868)	(64,011)
Net income	32,553	—	4,715	7,735	45,003
Issuance of units, net of offering costs	53,550	—	152,671	—	206,221
Contributions by partners	—	—	—	8,741	8,741
Balance at December 31, 2011	$286,945	$ —	$157,386	$11,292	$455,623

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

CRESTWOOD MIDSTREAM PARTNERS LP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. ORGANIZATION AND DESCRIPTION OF BUSINESS

Organization — Crestwood Midstream Partners LP ("CMLP") is a publicly traded Delaware limited partnership formed for the purpose of acquiring and operating midstream assets. Crestwood Gas Services GP LLC, our general partner ("General Partner") is owned by Crestwood Holdings Partners, LLC and its affiliates ("Crestwood Holdings"). Our common units are listed on the New York Stock Exchange ("NYSE") under the symbol "CMLP." In this report, unless the context requires otherwise, references to "we," "us," "our" or the "Partnership" are intended to mean the business and operations of CMLP and its subsidiaries.

On October 1, 2010, Quicksilver Resources Inc. ("Quicksilver") sold all of its ownership interests in CMLP to Crestwood Holdings ("Crestwood Transaction"), the terms of which included:

- Crestwood Holdings' purchase of a 100% interest in our General Partner;
- Crestwood Holdings' purchase of 5,696,752 common units and 11,513,625 subordinated units;
- Crestwood Holdings' purchase of a $58 million subordinated promissory note ("Subordinated Note") payable by CMLP which had a carrying value of approximately $58 million at closing; and
- $701 million in cash paid to Quicksilver and conditional consideration in the form of potential additional cash payments from Crestwood Holdings in 2012 and 2013 of up to $72 million in the aggregate, depending upon achievement of certain defined average volume targets above an agreed threshold for 2011 and 2012, respectively.

On October 18, 2010, subsequent to the closing of the Crestwood Transaction, the conflicts committee of our General Partner unanimously approved the conversion of our Subordinated Note payable into 2,333,712 common units in exchange for the outstanding balance of the subordinate note. In addition, on November 12, 2010, our subordination period ended resulting in the conversion of 11,513,625 subordinated units to common units on a one for one basis.

On October 4, 2010, our name changed from Quicksilver Gas Services LP to Crestwood Midstream Partners LP and our ticker symbol on the NYSE for our publicly traded common units changed from "KGS" to "CMLP."

Our ownership is as follows:

	December 31, 2011		
	Crestwood Holdings	Public	Total
General partner interest	1.9%	—	1.9%
Limited partner interest:			
Common unitholders	48.4%	33.3%	81.7%
Class C unitholders	0.1%	16.3%	16.4%
Total	50.4%	49.6%	100.0%

Neither CMLP nor our General Partner has any employees. Employees of Crestwood Holdings provide services to our General Partner pursuant to the Omnibus Agreement, dated October 8, 2010, among our General Partner and Crestwood Holdings ("Omnibus Agreement").

Description of Business — We are primarily engaged in the gathering, processing, treating, compression, transportation and sales of natural gas and the delivery of NGLs produced in the geological formations of the Barnett Shale in north Texas, the Avalon Shale area of southeastern New Mexico, the Fayetteville Shale in northwestern Arkansas, the Granite Wash in the Texas Panhandle and the Haynesville/Bossier Shale in western

Louisiana. More than 95% of our gross margin, which we define as total revenue less product purchases, is derived from fee-based service contracts, which minimizes our commodity price exposure and provides us with less volatile operating performance and cash flows. We have two systems located in basins that include NGL rich gas shale plays, (i) the Cowtown System, part of the Barnett segment and (ii) the Granite Wash System. In 2011, our systems located in NGL rich basins or rich gas shale plays contributed approximately 53% of our total revenue.

We conduct all of our operations in the midstream sector with three reportable operating segments. These operating segments reflect how we manage our operations and reflect the primary geographic areas in which we operate. The operating segments consist of Barnett, Fayetteville and Granite Wash. All of our operating segments are engaged in gathering, processing, treating, compression, transportation and sales of natural gas and delivery of NGLs in the United States (see Note 10 — "Segment Information").

Barnett:

Cowtown System — Located principally in Hood and Somervell Counties, Texas in the southern portion of the Fort Worth Basin, the Cowtown System includes:

- the Cowtown pipeline, which consists of a rich gas gathering system and related gas compression facilities that gathers natural gas produced by our customers and delivers it to the Cowtown or Corvette plants for processing;
- the Cowtown plant, which consists of two natural gas processing units that extract NGLs from the natural gas stream and deliver customers' residue gas and extracted NGLs to unaffiliated pipelines for sale downstream; and
- the Corvette plant, which extracts NGLs from the natural gas stream and delivers customers' residue gas and extracted NGLs to unaffiliated pipelines for sale downstream.

Residue gas from Cowtown may be delivered to Atmos Energy Corporation, Enterprise Texas Pipeline LLC and/or Energy Transfer Partners, LP ("Energy Transfer"). Residue gas from the Corvette plant is delivered to Energy Transfer. Extracted NGLs from the Cowtown and Corvette plants are delivered to West Texas Pipeline, LP and Lone Star NGL LLC for delivery to Mont Belivieu, Texas. For the year ended December 31, 2011, the Cowtown and Corvette plants had a total average throughput of 132 MMcfd of natural gas, resulting in average NGL recovery of 16,567 Bbld.

Lake Arlington System — Located in eastern Tarrant County, Texas, the Lake Arlington System consists of a dry gas gathering system and related gas compression facility. This system gathers natural gas produced by our customers and delivers it to Energy Transfer.

Alliance System — Located in northern Tarrant and southern Denton Counties, Texas, the Alliance System consists of a dry gas gathering system with a related dehydration, compression and an amine treating facility. This system gathers natural gas produced by our customers and delivers it to Energy Transfer and Crosstex Partners, LP ("Crosstex").

Fayetteville:

Twin Groves / Prairie Creek / Woolly Hollow Systems — Located in Conway and Faulkner Counties, Arkansas, the Twin Groves/Prairie Creek/Woolly Hollow Systems consist of three dry gas gathering, compression, dehydration and treating facilities. These systems gather natural gas produced by Billiton Petroleum ("BHP"), British Petroleum, Plc. ("BP"), and Exxon Mobil Corporation ("ExxonMobil") and interconnects with Ozark Gas Transmission, Boardwalk Gas Transmission and Fayetteville Express pipelines.

Rose Bud System — Located in White County, Arkansas, the Rose Bud System consists of a dry gas gathering system and a related compression facility. This system gathers natural gas produced by ExxonMobil and interconnects with Ozark Gas Transmission.

Wilson Creek System — Located in Van Buren County, Arkansas, the Wilson Creek System consists of a dry gas gathering system and a related compression facility. This system gathers natural gas produced by independent producers and interconnects with Ozark Gas Transmission.

Granite Wash:

Granite Wash System — Located in Roberts County, Texas, the Granite Wash System consists of:

- the Indian Creek rich gas gathering system and related compression facility; and
- the Indian Creek plant, which consists of a gas processing unit that extracts NGLs from the gas stream.

The residue gas and extracted NGLs are delivered to unaffiliated pipelines for sale downstream. This system gathers rich natural gas produced by Chesapeake, Linn Energy, LLC and Great Plains Operating, LLC and interconnects with Mid-America Pipeline, a subsidiary of Enterprise Products Partners, L.P. ("Enterprise Products") for ultimate delivery of NGLs to either Conway or Mont Belvieu, which historically has received premium pricing compared to the Conway NGL market. Additionally, residue gas interconnects with ANR Pipeline and Northern Natural Gas Pipeline to provide access to the Mid-Continent gas markets.

Other:

Las Animas System — Located in Eddy County, New Mexico, the Las Animas System consists of three dry gas gathering systems in the existing Morrow/Atoka trend which are located near the emerging Avalon Shale rich gas trend. The Las Animas System includes dedication of acreage from Bass Oil Production Company through 2017.

Sabine System — Located in Sabine Parish, Louisiana, the Sabine System consists of approximately 60 miles of high-pressure dry gas gathering pipelines. The system provides gathering and treating services for production from Chesapeake, Comstock Resources, Inc., Forest Oil Corporation, Wildcat Sabine Pipeline LLC and Devon Energy Corporation and interconnects with Gulf South Pipeline and Tennessee Gas Pipeline.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation — The accompanying financial statements and related notes present the consolidated balance sheets as of December 31, 2011 and December 31, 2010. They also include the consolidated statements of income, the consolidated statements of cash flows and changes in partners' capital for the periods ended December 31, 2011, 2010 and 2009.

The accompanying consolidated financial statements were prepared in accordance with U.S. generally accepted accounting principles ("GAAP") and in accordance with the rules and regulations of the Securities and Exchange Commission ("SEC").

Our consolidated financial statements include the accounts of CMLP and its 100% owned subsidiaries. We eliminate all inter-company balances and transactions in preparing consolidated financial statements.

Changes in Presentation — We have reclassified certain prior-year amounts to conform to the current-year's presentation. The amount of the reclassification is approximately $2.7 million and $2.1 million for the periods ended December 31, 2010 and 2009, respectively, from operations and maintenance expense to general and administrative expense. Such reclassifications had no impact on the respective period's expenses or operating income.

Use of Estimates — The preparation of the financial statements in accordance with GAAP requires management to make estimates and judgments that affect the reported amount of assets, liabilities, revenues and expenses and disclosure of contingent assets and liabilities that exist as of the date of the financial statements. Estimates and judgments are based on information available at the time such estimates and judgments are made. Although management believes the estimates are appropriate, actual results can differ from those estimates.

Cash and Cash Equivalents — We consider all highly liquid investments with a remaining maturity of three months or less at the time of purchase to be cash or cash equivalents. These cash equivalents consist principally of temporary investments of cash in short-term money market instruments.

Accounts receivable — Accounts receivable are due from Quicksilver and other customers. Each of our customers is reviewed as to credit worthiness prior to the extension of credit and on a regular basis thereafter. Although we do not require collateral, appropriate credit ratings are required. Receivables are generally due within 30 to 60 days. At December 31, 2011 and 2010, we have recorded no allowance for uncollectible accounts receivable. For the periods ended December 31, 2011 and 2010, we experienced no significant non-payment for services.

Property, Plant and Equipment — Property, plant and equipment is stated at cost less accumulated depreciation. Depreciation is computed using the straight-line method over the estimated useful lives of the assets. The cost of maintenance and repairs, which are not significant improvements, are expensed when incurred. Expenditures to extend the useful lives of the assets or enhance their productivity or efficiency from their original design or intended use are capitalized and depreciated over the expected remaining period of use.

Impairment of Long-Lived Assets — We review long-lived assets (or asset groups) for impairment whenever events or circumstances indicate that their carrying amounts may not be recoverable. If we determine that the sum of the estimated future undiscounted cash flows, expected to result from the use and eventual disposition of the assets, will not be sufficient to recover its carrying amount, we would record an impairment charge to reduce the carrying amount of the asset to its estimated fair value. We consider various factors in order to determine whether an indicator or impairment exists, including, but not limited to:

- A significant decline in an asset's market value;
- A significant change in the extent or manner in which an asset is used or a significant change in its physical condition;
- A significant adverse change in the legal or regulatory environment, or the overall business climate;
- An accumulation of costs significantly in excess of amounts initially anticipated; or
- A current expectation that it is more likely than not that an asset will be sold or disposed of significantly before the end of its estimated useful life.

Goodwill — Goodwill represents consideration paid in excess of the fair value of the identifiable assets acquired in a business combination. We evaluate goodwill for impairment annually on December 31, and whenever events or changes indicate that it is more likely than not that the fair value of a reporting unit is less than its carrying amount. Goodwill is tested for impairment using a two-step quantitative test.

The first step compares the fair value of the reporting unit to its carrying value, including goodwill. If the fair value exceeds the carry amount, goodwill of the reporting unit is not considered impaired. If however, the fair value does not exceed the carrying amount the second step compares the implied fair value to the carrying value of the reporting unit. If the carrying amount of a reporting unit's goodwill exceeds the implied fair value of that goodwill, the excess of the carrying value over the implied value is recognized as an impairment loss.

Deferred Financing Costs — Debt issuance costs are comprised of direct costs incurred in connection with the issuance of debt. Such costs are deferred and are reported on the balance sheet at cost, net of amortization. Debt issuance costs are amortized to interest expense over the stated term of the associated debt using the effective interest method.

Other Assets — Other assets consist of costs associated with pipeline license agreements, net of amortization. Pipeline license agreements provide us the right to construct, operate and maintain certain pipelines with local municipalities. The pipeline license agreements are amortized over a 20 year term.

Asset Retirement Obligations — We recognize and record a liability based on our legal or contractual obligation to retire tangible long-lived assets associated with right-of-way contracts we hold and our facilities whether owned or leased. We record the fair value of the liability for asset retirement obligations in the period in which it is legally or contractually incurred, if a reasonable estimate of its fair value can be made. Upon initial recognition of the asset retirement liability, an asset retirement cost is capitalized by increasing the carrying amount of the long-lived asset by the same amount as the liability. In periods subsequent to the initial measurement, the asset retirement cost is allocated to depreciation expense using a straight-line method over the asset's useful life. In addition, the carrying value of the liability is subject to accretion over the same period. Changes in the liability for the asset retirement obligation are recognized for the passage of time, via accretion, and revisions to either the timing or the amount of the estimated cash flows.

Environmental Liabilities — Liabilities for environmental contingencies, including environmental remediation costs, are charged to expense when it is probable that a liability has been incurred and the amount of the assessment or remediation can be reasonably estimated.

Revenue Recognition — Our primary service offerings are the gathering, processing, treating, compression, transportation and sales of natural gas. We have fixed-fee contracts under which we receive revenue based on the volume of natural gas gathered, processed and treated or compressed. See Note 16 — "Transactions with Related Parties" for information regarding revenue derived from related parties.

We also have percent-of-proceeds contracts where we receive revenue based on the value of products sold to third parties which we present as Product Sales. The contracts related to Product Sales accounted for approximately 3% of gross margin in 2011. We recognize revenue when all of the following criteria are met:

- persuasive evidence of an exchange arrangement exists;
- services have been rendered or products delivered;
- the price for its services is fixed or determinable; and
- collectability is reasonably assured.

Income Taxes — We qualify to be treated as a master limited partnership for federal income tax purposes because at least 90% of our gross income for each taxable year has been and is derived from specified investments and activities. We are subject to the Texas margin tax that requires tax payments at a maximum statutory effective rate of 0.7% of the gross revenue apportioned to Texas. The margin tax qualifies as an income tax under GAAP, which requires us to recognize currently the impact of this tax on the temporary differences between the financial statement assets and liabilities and their tax basis attributable to such tax.

Earnings per Limited Partner Unit — Our net income is allocated to the General Partner and the limited partners, in accordance with their respective ownership percentages, after giving effect to incentive distributions paid to the General Partner. Basic earnings per unit are computed by dividing net income attributable to limited partner unitholders by the weighted-average number of limited partner units outstanding during each period. Diluted earnings per unit are computed using the treasury stock method, which considers the impact to net income and limited partner units from the potential issuance of limited partner units and conversion of debt into limited partner units.

Segment Information — Our operations include three reportable operating segments. These operating segments reflect how we manage our operations and the primary geographic areas in which we operate. Our operating segments consist of Barnett, Fayetteville and Granite Wash. All of our operating segments are engaged in the gathering, processing, treating, compression, transportation and sale of natural gas and the delivery of NGLs in the United States.

Fair Value of Financial Instruments — Accounting Standards Codification Topic 820, *Fair Value Measurement* ("ASC 820") defines fair value as the amount a willing buyer or seller in an active market could reasonably expect to pay or receive in a current sale. This standard characterizes inputs used in determining fair value according to a hierarchy that prioritizes those inputs based upon the degree to which they are observable. The three levels of the fair value hierarchy are as follows:

Level 1 — inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities that the reporting entity has the ability to access at the measurement date.

Level 2 — inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly.

Level 3 — inputs are unobservable for the asset or liability.

The fair value of cash and cash equivalents, accounts receivable, accounts payable and our senior secured credit facility, as amended, dated effective October 1, 2010 ("Credit Facility") approximate their carrying amounts as of December 31, 2011.

The fair value of our $200 million aggregate principal amount of 7.75% senior notes due 2019 ("Senior Notes") is determined using Level 1 inputs from public sources. We obtain the quoted market price at the measurement date to calculate the fair value. As of December 31, 2011, our $200 million principal amount Senior Notes had a fair value of approximately $197 million.

Equity-Based Compensation — At time of issuance of phantom units, management of our General Partner determines whether they will be settled in cash or settled in our units. Equity-based awards are valued at the closing market price of our common units on the date of grant, which reflects the fair value of such awards. In addition, for those awards that will be settled in cash, the associated liability is re-measured at every balance sheet date through settlement, such that the vested portion of the liability is adjusted to reflect its revised fair value through compensation expense. We generally recognize the expense associated with the award over the vesting period.

Recently Issued Accounting Standards

Accounting standard-setting organizations frequently issue new or revised accounting rules. We regularly review all new pronouncements to determine their impact, if any, on our financial statements. We have included only the new or revised accounting pronouncements that are applicable to us.

In September 2011, the Financial Accounting Standards Board amended the accounting literature for goodwill impairment testing by issuing an update. Accounting Standards Updates ("ASU") 2011-08 ("ASU 2011-08") amended guidance provides an entity with an option to first assess qualitative factors to evaluate whether it is more likely than not that the fair value of a reporting unit is less than the carry amount as the basis to determine if the two-step goodwill impairment is required. The effective date of ASU 2011-08 is for annual and interim goodwill tests for fiscal years beginning after December 15, 2011, and early adoption is permitted. We have not elected to early adopt ASU 2011-08 and we do not believe that the amended guidance will have a material impact on our consolidated financial statements when adopted.

3. ACQUISITIONS

Las Animas Acquisition

On February 16, 2011, we completed the acquisition of certain midstream assets in the Avalon Shale play from a group of independent producers for $5.1 million ("Las Animas Acquisition").

At the time of the acquisition, the Las Animas assets consisted of approximately 46 miles of natural gas gathering pipeline located in the Morrow/Atoka trend and the emerging Avalon Shale trend in southeastern

New Mexico ("Las Animas System"). The pipelines are supported by long-term, fixed-fee contracts which include existing Morrow/Atoka production and dedications of approximately 55,000 acres. The Avalon Shale is a NGL rich oil and gas field that is part of the Permian Basin.

The Las Animas Acquisition was recorded in property, plant and equipment at fair value of $5.1 million. As of December 31, 2011, we recognized approximately $4.8 million in revenues and $0.1 million in operating income related to this acquisition.

Frontier Gas Acquisition

On April 1, 2011, we completed the acquisition of certain midstream assets in the Fayetteville Shale and the Granite Wash from Frontier Gas Services, LLC for approximately $345 million ("Frontier Gas Acquisition").

Fayetteville

At the time of the acquisition, the Fayetteville assets consisted of approximately 130 miles of high pressure and low pressure gathering pipelines in northwestern Arkansas with capacity of approximately 510 MMcfd, treating capacity of approximately 165 MMcfd and approximately 35,000 hp of compression ("Fayetteville System"). The Fayetteville System interconnects with multiple interstate pipelines which serve the Fayetteville Shale and are supported by long-term, fixed-fee contracts with producers who dedicated approximately 100,000 acres in the core of the Fayetteville Shale to us. These contracts have initial terms that extend through 2020 and include an option, to either party to the contract, to extend through 2025.

Granite Wash

At the time of the acquisition, the Granite Wash assets consisted of a 28 mile pipeline system and a 36 MMcfd cryogenic processing plant in the Texas Panhandle ("Granite Wash System"). The Granite Wash System is supported by more than 13,000 dedicated acres and long-term contracts with initial terms that extend through 2022. The Granite Wash System has emerged as a NGL rich natural gas play with active drilling programs by various producers.

In third quarter 2011, we finalized the Frontier Acquisition purchase price as follows (In thousands):

Purchase Price:	
Total purchase price	$344,562
Purchase Price Allocation:	
Accounts receivable	$ 335
Prepaid expenses and other	750
Capital lease asset	8,587
Property, plant and equipment	135,918
Intangible assets	114,200
Other assets	178
Total assets	$259,968
Current portion of capital leases	$ 2,576
Accounts payable, accrued expenses and other	64
Long-term capital leases	6,011
Asset retirement obligations	383
Total liabilities	$ 9,034
Goodwill	$ 93,628

The $338 million purchase price paid at closing was financed through a combination of equity and debt as described in Notes 10 — “Long-Term Debt” and Note 17 — “Partners’ Capital and Distributions”. The total purchase price paid of $345 million also includes $4 million in capital expenditures and $3 million of inventory purchased which is included in property, plant and equipment. Transaction costs for the year ended December 31, 2011 were $4.8 million of which $2.3 million was recorded in general and administrative expense and $2.5 million was recorded in interest expense. As of December 31, 2011 we recognized approximately $59 million in revenues and $5.4 million in operating income related to this acquisition.

Tristate Acquisition

On November 1, 2011, we acquired Tristate Sabine, LLC (“Tristate”) from affiliates of Energy Spectrum Capital, Zwolle Pipeline, LLC, and Tristate’s management for approximately $73 million in cash consideration comprised of $65 million paid at closing plus a deferred payment of $8 million one year following the closing date, subject to customary post-closing adjustments (“Tristate Acquisition”).

At the time of the acquisition, the Tristate assets located in Haynesville/Bossier Shale consisted of approximately 60 miles of high pressure and low pressure gathering pipelines in western Louisiana with capacity of approximately 100 MMcfd and treating capacity of approximately 80 MMcfd (“Sabine System”). The Sabine System is supported by long-term, fixed-fee contracts with producers who dedicated approximately 20,000 acres to us. These contracts have various initial terms that extend through 2019 and 2021. The final purchase price allocation is pending the finalization of the valuation of the assets acquired, liabilities assumed and settlement of the deferred amounts due in the Tristate Acquisition. The preliminary purchase price allocation is as follows (In thousands):

Purchase price:	
Cash	$65,000
Deferred payment	8,000
Total purchase price	$73,000
Preliminary purchase price allocation:	
Cash	$ 589
Accounts receivable	2,564
Prepaid expenses and other	365
Property, plant and equipment	56,261
Intangible assets	16,000
Total assets	$75,779
Accounts payable, accrued expenses and other	$ 1,915
Asset retirement obligation	864
Total liabilities	$ 2,779
Total	$73,000

Transaction costs of $0.3 million were recognized in general and administrative expense during 2011. As of December 31, 2011, we recognized approximately $1.9 million in revenues and $0.9 million in operating income related to this acquisition.

The following table is the presentation of income for the years ended December 31, 2011 and 2010 as if we had completed the Frontier Gas, Tristate and Las Animas Acquisitions on January 1, 2010 (In thousands):

	Year Ended December 31, 2011		
	Crestwood Midstream Partners LP (1)	Proforma Adjustment (2)	Combined
Revenue	$ 205,820	$ 25,827	$ 231,647
Gain from exchange of property, plant and equipment	1,106	—	1,106
Operating expenses	(133,055)	(22,911)	(155,966)
Operating income	$ 73,871	$ 2,916	$ 76,787
Basic earnings per limited partner unit:	$ 1.00		$ 0.87
Diluted earnings per limited partner unit:	$ 1.00		$ 0.87
Weighted-average number of limited partner units:			
Basic	37,206		38,835
Diluted	37,320		38,949

	Year Ended December 31, 2010		
	Crestwood Midstream Partners LP	Proforma Adjustment (3)	Combined
Revenue	$113,590	$ 74,217	$ 187,807
Operating expenses	(65,718)	(70,295)	(136,013)
Operating income	$ 47,872	$ 3,922	$ 51,794
Basic earnings per limited partner unit:	$ 1.11		$ 0.80
Diluted earnings per limited partner unit:	$ 1.03		$ 0.75
Weighted-average number of limited partner units:			
Basic	29,070		35,561
Diluted	31,316		37,807

(1) Includes eleven months of operating income from the Las Animas Acquisition, from February to December 2011, nine months of operating income for the Frontier Gas Acquisition, from April 2011 to December 2011 and two months of operating income for the Tristate Acquisition, from November 2011 to December 2011, subsequent to acquisition.

(2) Represents approximately one month of operating income for the Las Animas Acquisition, the first quarter of 2011 of operating income for the Frontier Gas Acquisition and the first ten months of operating income for the Tristate Acquisition.

(3) Represents operating income for the Las Animas Acquisition, the Frontier Gas Acquisition and the Tristate Acquisition for the year ended December 31, 2010.

4. NET INCOME PER LIMITED PARTNER UNIT

The following is a reconciliation of the limited partner units used in the basic and diluted earnings per unit calculations for 2011, 2010 and 2009 (In thousands, except per unit data):

	Year Ended December 31,		
	2011	2010	2009
Limited partners' interest in net income from continuing operations	$37,268	$32,346	$33,286
Limited partners' interest in net loss from discontinued operations	—	—	(1,959)
Limited partners' interest in net income	$37,268	$32,346	$31,327
Impact of interest on subordinated note	—	—	2,038
Income available assuming conversion of Subordinated Note	$37,268	$32,346	$33,365
Weighted-average limited partner units - basic (1)	37,206	29,070	24,057
Effect of unvested phantom units	114	2,246	486
Effect of subordinated note (2)	—	—	3,646
Weighted-average limited partner units - diluted	37,320	31,316	28,189
Basic earnings per unit:			
From continuing operations per limited partner	$ 1.00	$ 1.11	$ 1.38
From discontinued operations per limited partner	$ —	$ —	$ (0.08)
Net income per limited partner	$ 1.00	$ 1.11	$ 1.30
Diluted earnings per unit:			
From continuing operations per limited partner	$ 1.00	$ 1.03	$ 1.25
From discontinued operations per limited partner	$ —	$ —	$ (0.07)
Net income per limited partner	$ 1.00	$ 1.03	$ 1.18
Assumed conversion price (2)	$ —	$ —	$ 15.28

(1) Includes 6,596,635 Class C units as of December 31, 2011.

(2) Assumes that Subordinated Note is converted using the lesser of average closing price per unit or final closing price on December 31. The impact of the Subordinated Note is dilutive for only 2009.

See Note 10 — "Long-Term Debt" for more information regarding the conversion of the Subordinated Note.

5. DISCONTINUED OPERATIONS

In November 2009, Quicksilver and our General Partner mutually agreed to waive both parties' rights and obligations to transfer ownership of the Hill County Dry System ("HCDS") from Quicksilver to us, which we refer to as the Repurchase Obligation Waiver. The Repurchase Obligation Waiver caused derecognition of the assets and liabilities directly attributable to the HCDS, most significantly the property, plant and equipment and repurchase obligation, beginning in November 2009. In addition, the Repurchase Obligation Waiver caused the elimination of the HCDS' revenues and expenses from our consolidated results of operations beginning in November 2009. The revenues and expenses directly attributable to the HCDS for the periods prior to November 2009 have been retrospectively reported as discontinued operations based upon our decision not to purchase the system from Quicksilver as follows (In thousands):

	Year Ended December 31, 2009
Revenues	$ 3,771
Operating Expenses	(3,718)
Interest Expense	(2,045)
Loss from discontinued operations	$(1,992)

6. PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment consist of the following (In thousands):

	Depreciable Life	December 31, 2011	December 31, 2010
Gathering systems	20 years	$298,207	$158,975
Processing plants and compression facilities	20-25 years	429,908	365,208
Construction in progress	—	47,073	26,385
Rights-of-way and easements	20 years	50,085	32,054
Land	—	4,674	4,251
Buildings and other	5-40 years	5,958	3,494
		835,905	590,367
Accumulated depreciation		(89,860)	(58,996)
Property, plant and equipment, net		$746,045	$531,371

Property, plant and equipment increased principally due to our acquisitions during 2011. Notably, the Frontier Gas Acquisition increased assets by approximately $144 million, which consisted of approximately $96.7 million in gathering systems, $38.5 million in processing plants and compression equipment, $7.3 million in rights-of-way and easements and $1.6 million in buildings and other assets. The Tristate Acquisition increased assets by approximately $55.4 million, which consisted of approximately $28.5 million in gathering systems, $11.4 million in facilities, $7.2 million in construction in process, $7.9 million in rights-of-way and easements and $0.4 million in land and other assets. Other increases during the year represent normal additions in the ordinary course of operations.

We recognized $30.9 million, $21.8 million and $23.0 million of depreciation expense on property, plant and equipment during 2011, 2010 and 2009, respectively.

7. INTANGIBLE ASSETS

Intangible assets consist of gas gathering and processing contracts. The following table summarizes the intangibles associated with the purchase of the Fayetteville, Granite Wash and Sabine Systems during 2011 (In thousands):

	December 31, 2011		
	Cost	Accumulated Amortization	Net Book Value
Intangibles - subject to amortization:			
Gas contracts	$130,200	$2,440	$127,760

The intangible assets have useful lives of 6 to 17 years, which is determined based on the customer contract life. Amortization expense recorded for the year ended December 31, 2011 was approximately $2.4 million. The expected amortization of the intangible assets for the years ending December 31 is as follows (In thousands):

2012	$ 6,652
2013	8,007
2014	9,176
2015	9,729
Thereafter	94,196
Total	$127,760

8. GOODWILL

During 2011, goodwill was recorded in connection with the Frontier Gas Acquisition. At December 31, 2011, approximately $93.7 million was recorded as goodwill, consisting of $76.8 million allocated to Fayetteville and $16.9 million allocated to Granite Wash. Goodwill represents consideration paid in excess of the fair value of the net identifiable assets acquired in a business combination. We evaluate goodwill for impairment annually on December 31, and whenever events or changes indicate that it is more likely than not that the fair value of a reporting unit is less than its carrying amount. Accounting standards require that goodwill must be tested at a reporting unit level. We have three operating segments with five reporting units (See Note 10 — "Segment Information").

Accounting standards provide a two-step test where the first step compares the fair value of the reporting unit to its carrying value, including goodwill. If the fair value exceeds its carry amount, goodwill of the reporting unit is not considered impaired. If, however, the fair value does not exceed the carrying amount, the second step compares the implied fair value of the reporting unit's goodwill to its carrying value. If the carrying amount of the goodwill of a reporting unit exceeds the implied fair value of that goodwill, the excess of the carrying value over the implied fair value is recognized as an impairment loss.

At December 31, 2011, we completed step one of the impairment test for each reporting unit. Based on our step one on the results of this testing, we concluded that each reporting unit's fair value was in excess of their respective carrying value, including goodwill. Therefore, no goodwill impairment was recognized during the year ending December 31, 2011. All goodwill was recognized in connection with acquisitions in 2011.

9. ACCOUNTS PAYABLE, ACCRUED EXPENSES AND OTHER

Accounts payable, accrued expenses and other consists of the following (In thousands):

	December 31, 2011	December 31, 2010
Accrued expenses	$ 3,175	$1,736
Accrued property taxes	5,204	—
Accrued product purchases payable	3,594	—
Tax payable	1,545	280
Interest payable	4,788	726
Accounts payable	5,128	—
Deferred payment on Tristate Acquisition	8,000	—
Other	360	175
	$31,794	$2,917

The deferred payment on Tristate Acquisition of $8.0 million, is subject to customary post-closing adjustments associated with the Tristate Acquisition (see Note 3 — "Acquisitions").

10. LONG-TERM DEBT

Debt consists of the following (In thousands):

	December 31, 2011	December 31, 2010
Credit Facility	$312,500	$283,504
Senior Notes	200,000	—
	512,500	283,504
Current maturities of debt	—	—
Long-term debt	$512,500	$283,504

The following table summarizes our debt payments due by period (In thousands):

	Payments Due by Period						
Long-Term Debt	**Total**	**2012**	**2013**	**2014**	**2015**	**2016**	**Thereafter**
Credit Facility, due October 2015	$312,500	$—	$—	$—	$312,500	$—	$ —
Senior Notes, due April 2019	200,000	—	—	—	—	—	200,000
Total long-term debt	$512,500	$—	$—	$—	$312,500	$—	$200,000

Credit Facility — Our Credit Facility allows for revolving loans, letters of credit and swingline loans in an aggregate amount of up to $500 million. On April 1, 2011, we entered into an agreement with certain lenders of our Credit Facility, which expanded our borrowing capacity from $400 million to $500 million. The Credit Facility is secured by substantially all of CMLP's and its subsidiaries' assets and is guaranteed by CMLP's subsidiaries. Borrowings under the Credit Facility bear interest at London Interbank Offered Rate ("LIBOR") plus an applicable margin or a base rate as defined in the credit agreement. Under the terms of the Credit Facility, the applicable margin under LIBOR borrowings was 3.0% at December 31, 2011. Based on our results through December 31, 2011, our total borrowing capacity was $500 million and our borrowings were $312.5 million. During 2011, our average and maximum outstanding borrowings were $325.5 million and $282 million, respectively. The weighted-average interest rate as of December 31, 2011 and 2010 was 3.3% and 3.1%.

Our Credit Facility requires us to maintain:

- a ratio of our consolidated trailing 12-month EBITDA to our net interest expense of not less than 2.5 to 1.0, (as defined in the credit agreement); and
- a ratio of total indebtedness to consolidated trailing 12-month EBITDA of not more than 5.0 to 1.0, or not more than 5.5 to 1.0 for up to nine months following certain acquisitions (as defined in the credit agreement).

As of December 31, 2011, we were in compliance with these financial covenants.

The Credit Facility contains restrictive covenants that prohibit the declaration or payment of distributions by us if a default then exists or would result therefrom, and otherwise limits the amount of distributions that we can make. An event of default, may result in the acceleration of our repayment of outstanding borrowings under the Credit Facility, the termination of the Credit Facility and foreclosure on collateral.

Subordinated Note — In August 2007, we executed the Subordinated Note payable to Quicksilver in the principal amount of $50.0 million. The Subordinated Note was assigned to Crestwood Holdings as part of the Crestwood Transaction on October 1, 2010. Our Credit Facility required us to terminate the Subordinated Note through the issuance of additional common units during the fourth quarter of 2010. The conversion into common units was determined based upon the average closing common unit price for a 20 trading-day period that ended October 15, 2010. The conversion of the Subordinated Note was unanimously approved by the conflicts committee of our General Partner's board of directors and resulted in the issuance of 2,333,712 of our common units to Crestwood Holdings in exchange for the outstanding balance of the Subordinated Note at the time of the conversion.

Bridge Loan Commitments — In February 2011, in connection with the Frontier Gas Acquisition, we obtained commitments from multiple lenders for senior unsecured bridge loans in an aggregate amount up to $200 million. The commitment was not drawn and was terminated on April 1, 2011 in connection with the issuance of the Senior Notes described below. We recognized $2.5 million of commitment fees in the second quarter of 2011, which is included in interest expense, related to the bridge loans.

Senior Notes — On April 1, 2011, we issued $200 million of Senior Notes, which accrue interest at the rate of 7.75% per annum and mature in April 2019. Our obligations under the Senior Notes are guaranteed on an unsecured basis by our current and future domestic subsidiaries. The accrued interest is payable in cash semi-annually in arrears on April 1 and October 1 of each year, commencing on October 1, 2011. The proceeds were used to partially finance the Frontier Gas Acquisition. Our Senior Notes require us to maintain a ratio of our consolidated trailing 12-month EBITDA (as defined in the indenture governing the Senior Notes) to fixed charges of at least 1.75 to 1.0. As of December 31, 2011, we were in compliance with this covenant.

Guarantor Subsidiaries — Our subsidiaries are 100% owned by CMLP and they are full and unconditional, joint and several guarantors of our debt. CMLP has no independent assets and no operations.

11. ASSET RETIREMENT OBLIGATIONS

The following table provides a reconciliation of the changes in the asset retirement obligations generally associated with plant, property and equipment during the years ended December 31, 2011 and 2010 (In thousands):

	December 31, 2011	December 31, 2010
Beginning asset retirement obligations	$ 9,877	$8,919
Incremental liability incurred	140	447
Changes in estimates	(724)	—
Acquisitions	1,744	—
Accretion expense	508	511
Ending asset retirement obligations	$11,545	$9,877

As of December 31, 2011, no assets are legally restricted for use in settling asset retirement obligations.

12. CAPITAL LEASES

With the Frontier Gas Acquisition, we assumed compressor leases in the amount of $8.6 million which are accounted for as capital leases. In addition, we recorded $1.9 million in amortization expense related to these capital leases for the year ended December 31, 2011. There were no capital leases during 2010.

The total liability outstanding at December 31, 2011 related to these leases is $6.6 million. Future minimum lease payments related to capital leases are as follows (In thousands):

2012	2,860
2013	2,860
2014	1,162
Total payments	6,882
Imputed interest	(260)
Present value of future payments	$6,622

13. COMMITMENTS AND CONTINGENT LIABILITIES

In May 2011, a putative class action lawsuit, Ginardi v. Frontier Gas Services, LLC, et al, was filed in the United States District Court of the Eastern District of Arkansas against Frontier Gas Services, LLC, Chesapeake Energy Corporation, BHP Billiton Petroleum, Kinder Morgan Treating, LP, and Crestwood Arkansas Pipeline LLC (which was served in August 2011) No 4:11-cv-0420 BRW. The lawsuit alleges that the defendants' operations pollute the atmosphere, groundwater, and soil with allegedly harmful gases, chemicals, and compounds and the facilities create excessive noise levels constituting trespass, nuisance and annoyance ("Ginardi case"). In December 2011, a putative class action lawsuit, George Bartlett, et al, v. Frontier Gas Services, LLC, et al including Crestwood Arkansas Pipeline, LLC, Chesapeake Energy Corporation, and Kinder Morgan Treating LP, was filed in the United States District Court of the Eastern District of Arkansas, No 4: 11-cv-0910 BSM alleging the same causes as in the Ginardi case ("Bartlett case"). In each of the Ginardi and the Bartlett case, the plaintiffs seek compensatory and punitive damages of loss of use and enjoyment of property, contamination of soil and ground water, air and atmosphere and seek future monitoring. We have filed answers in the Ginardi and Bartlett case denying any liability. The court has not yet certified either lawsuit as a class action. While we cannot reasonably quantify our ultimate liability, if any, for the payment of any damages or other remedial actions, neither the Ginardi nor the Bartlett cases have had, nor are they expected to have, a material impact on our results of operation, cash flows or financial condition. We intend to vigorously defend against both claims and to mitigate any clams by pursuing any indemnification obligations to which we may be entitled with respect to the properties as well as any coverage from our insurance.

From time-to-time, we are party to certain legal, regulatory or administrative proceedings that arise in the ordinary course and are incidental to our business. However, except as set forth above, there are currently no such pending proceedings to which we are a party that our management believes will have a material adverse effect on our results of operations, cash flows or financial condition. However, future events or circumstances, currently unknown to management, will determine whether the resolution of any litigation or claims will ultimately have a material effect on our results of operations, cash flows or financial condition in any future reporting periods.

Casualties or Other Risks — We maintain coverage in various insurance programs, which provide us with property damage and other coverages which are customary for the nature and scope of our operations.

Management of our General Partner believes that we have adequate insurance coverage, although insurance will not cover every type of loss that we might occur. As a result of insurance market conditions, premiums and deductibles for certain insurance policies have increased substantially and, in some instances, certain insurance may become unavailable, or available for only reduced amounts of coverage. As a result, we may not be able to renew existing insurance policies or procure other desirable insurance on commercially reasonable terms, if at all.

If we were to incur a significant loss for which we were not adequately insured, the loss could have a material impact on our results of operations, cash flows or financial condition. In addition, the proceeds of any available insurance may not be paid in a timely manner and may be insufficient if such an event were to occur. Any event that interrupts our revenues, or which causes us to make significant expenditures not covered by insurance, could reduce our ability to meet our financial obligations.

Regulatory Compliance — In the ordinary course of our business, we are subject to various laws and regulations. In the opinion of our management, compliance with current laws and regulations will not have a material effect on our results of operations, cash flows or financial condition.

Environmental Compliance — Our operations are subject to stringent and complex laws and regulations pertaining to health, safety, and the environment. As an owner or operator of these facilities, we are subject to laws and regulations at the federal, state and local levels that relate to air and water quality, hazardous and solid waste management and disposal and other environmental matters. The cost of planning, designing, constructing and operating our facilities must incorporate compliance with environmental laws and regulations and safety standards. Failure to comply with these laws and regulations may trigger a variety of administrative, civil and potentially criminal enforcement measures. At December 31, 2011 and 2010, we had recorded no liabilities for environmental matters.

Commitments — The following table summarizes our commitment obligations as of December 31, 2011 (In thousands):

	Payments Due by Period						
	Total	**2012**	**2013**	**2014**	**2015**	**2016**	**Thereafter**
Operating Leases [1]	$4,885	$2,538	$1,068	$625	$433	$13	$208
Total	$4,885	$2,538	$1,068	$625	$433	$13	$208

(1) We lease compressors, office buildings, automobiles and other property under operating leases.

We recognized $7.7 million, $0.9 million and $1.6 million of rental expense during 2011, 2010 and 2009, respectively.

14. INCOME TAXES

No provision for federal income taxes is included in our results of operations. Accordingly, each partner is responsible for its share of federal and state income tax. Net earnings for financial statement purposes may differ significantly from taxable income reportable to each partner as a result of differences between the tax basis and financial reporting basis of assets and liabilities.

Prior to the closing of the Crestwood Transaction on October 1, 2010, our activity was included in Quicksilver's Texas Franchise tax combined report. As a result, there was a deferred tax liability recorded to reflect the change in tax basis and financial reporting basis of our assets and liabilities. As a result of the change in the organizational structure with the Crestwood Transaction, a deferred income tax liability of $0.8 million was reversed in 2010 as no state tax liability was expected to be recognized.

Effective with the closing of the Crestwood Transaction, we were no longer included in Quicksilver's Texas Franchise tax combined report, and we filed a separate report under Crestwood Holdings. Therefore, our current tax liability is assessed based on 0.7% of the gross revenue apportioned to Texas. Income tax expense was $0.2 million for the period from October 1, 2010 through December 31, 2010, subsequent to the closing of the Crestwood Transaction. Income tax expense was $1.3 million for the year ended December 31, 2011.

The closing of the Crestwood Transaction caused a technical termination of Quicksilver Gas Services LP as defined by the Internal Revenue Code. One of the significant consequences of a technical termination is its impact on a partnership's filing requirement for federal income tax purposes. Generally, a partnership's taxable year closes with respect to all partners on the date on which a partnership terminates. A terminated partnership must file a federal income tax return for the short period ending on the date of the sale that resulted in the technical termination. A second short period return is then required to be filed for the remainder of the taxable year of that new partnership. Our tax status is, however, unaffected by these filings and the technical termination except as indicated above.

We evaluate the uncertainty in tax positions taken or expected to be taken in the course of preparing our consolidated financial statements to determine whether the tax positions are "more-likely-than-not" of being sustained by the applicable tax authority. Tax positions with respect to tax at the partnership level deemed not to meet the "more-likely-than-not" threshold would be recorded as a tax benefit or expense in the current year. We have concluded that there is no impact on our operations for the year ended December 31, 2011 and that no provision for income tax is required for these consolidated financial statements. However, our conclusions regarding the evaluation are subject to review and may be adjusted at a later date based on factors including, but not limited to, on-going analyses of tax laws, regulations and interpretations thereof.

15. EQUITY PLAN

Awards of phantom units and restricted units have been granted under our Third Amended and Restated 2007 Equity Plan ("2007 Equity Plan") which permits the issuance of up to 750,000 units. The following table summarizes the current year activity regarding the 2007 Equity Plan:

	Payable In Cash		Payable In Units	
	Units	Weighted-Average Grant Date Fair Value	Units	Weighted-Average Grant Date Fair Value
Unvested - December 31, 2009	33,240	$20.90	485,672	$12.75
Vested - phantom units	(33,240)	21.64	(695,582)	15.29
Issued - phantom units	—	—	333,961	23.38
Issued - restricted units	—	—	4,042	27.11
Cancelled - phantom units	—	—	(6,567)	24.44
Unvested - December 31, 2010	—	$ —	121,526	$27.11
Vested	—	—	—	—
Issued - phantom units	15,294	26.77	19,411	27.56
Issued - restricted units	—	—	10,000	27.70
Cancelled - phantom units	(1,948)	29.31	(22,142)	27.16
Unvested - December 31, 2011	13,346	$26.40	128,795	$27.22

At December 31, 2010, we had total unrecognized compensation expense of $2.6 million related to the 2007 Equity Plan. We recognized compensation expense of approximately $1.0 million during 2011. Equity grants during 2011 had an estimated grant date value of $1.2 million. We had unrecognized compensation expense of $2.2 million at December 31, 2011 which is generally expected to be recognized on a straight-line basis over the vesting period of three years except for grants to non-employee directors of our General Partner in lieu of cash compensation, which vest after one year. No phantom units vested during 2011.

On January 4, 2010, we awarded annual equity grants totaling 211,600 phantom units to the non-management directors, executive officers of our General Partner and employees seconded to us. Each phantom unit settled in CMLP units and had a grant date value of $21.15, which were generally expected to be recognized over the vesting period of three years except for grants to non-employee directors of our General Partner in lieu of cash compensation, which grants vest after one year. As a result of the Crestwood Transaction, during the fourth quarter we recognized compensation expense of approximately $3.6 million, resulting in 523,011 units vesting and 347,888 units issued after the effect of taxes paid, which is attributable to the acceleration of CMLP's equity-based compensation program resulting from the change-in-control of provisions of the 2007 Equity Plan. This affected all outstanding units and results in there being no unvested units outstanding immediately thereafter.

On December 10, 2010, we awarded annual equity grants totaling 126,403 phantom units, including 4,042 restricted units, to the executive officers of our General Partner and employees of Crestwood Holdings. Each phantom unit settles in CMLP units and had a grant date value of $27.11, which will be recognized generally over a vesting period of three years except for grants to non-employee directors of our General Partner in lieu of cash compensation, which grants vest after one year.

As of December 31, 2010 and 2011, there were 640,480 and 633,211 units available for issuance under the 2007 Equity Plan, respectively.

On January 3, 2011, in accordance with our annual non-employee director compensation plans, we awarded non-employee director grants totaling 18,391 phantom units. Each phantom unit will settle in units and had a grant date value of $27.73.

Other grants were issued at various times throughout 2011 consisted of 26,314 phantom units, including 10,000 restricted units, 1,020 phantom units that settle in common units and 15,294 phantom units that settle in cash (valued at approximately $0.5 million as of December 31, 2011).

On January 3, 2012, in accordance with our annual non-employee director compensation plans, we awarded non-employee director grants totaling 14,315 phantom units. Each phantom unit will settle in units and had a grant date value of $32.13.

On January 13, 2012, in accordance with our annual employee compensation plans, we awarded employee equity grants totaling 110,846 phantom units, including 10,000 restricted units, to the executive officers of our General Partner and employees of Crestwood Holdings. Each phantom unit will settle in units and had a grant date value of $30.04, which will be recognized on a straight-line basis over the vesting period of three years.

16. TRANSACTIONS WITH RELATED PARTIES

Omnibus Agreement — In October 2010, concurrent with the Crestwood Transaction, we entered into an Omnibus Agreement with Crestwood Holdings and our General Partner that addresses the following matters:

- restrictions on Crestwood Holdings' ability to engage in certain midstream business activities or own certain related assets in the Hood, Somervell, Johnson, Tarrant, Hill, Parker, Bosque and Erath Counties in Texas;
- Crestwood Holdings' obligation to indemnify us for certain liabilities and our obligation to indemnify Crestwood for certain liabilities;
- our obligation to reimburse Crestwood Holdings for all expenses incurred by Crestwood Holdings (or payments made on our behalf) in conjunction with Crestwood Holdings' provision of general and administrative services to us, including salary and benefits of Crestwood Holdings personnel, our public company expenses, general and administrative expenses and salaries and benefits of our executive management who are Crestwood Holdings' employees;
- our obligation to reimburse Crestwood Holdings for all insurance coverage expenses it incurs or payments it makes with respect to our assets; and
- our obligation to reimburse Crestwood Holdings for all expenses incurred by Crestwood Holdings (or payments made on our behalf) in conjunction with Crestwood Holdings' provision of services necessary to operate, manage and maintain our assets.

Any or all of the provisions of the Omnibus Agreement are terminable by Crestwood Holdings at its option if our General Partner is removed without cause and units held by our General Partner and its affiliates are not voted in favor of that removal. The Omnibus Agreement terminates on the earlier of August 10, 2017 or at such times as Crestwood Holdings ceases to own or control a majority of the issued and outstanding voting securities of our General Partner.

Reimbursements to Crestwood Holdings pursuant to the Omnibus Agreement consisted of payments of $16.8 million in 2011 and $4.4 million in 2010 related to expenses and payments incurred on our behalf under the Omnibus Agreement.

Prior to the Crestwood Transaction we were party to an omnibus agreement with Quicksilver and our General Partner which contained similar contractual terms. This omnibus agreement with Quicksilver was terminated upon completion of the Crestwood Transaction. Reimbursements to Quicksilver pursuant to this agreement were $4.3 million in 2010 and $5.2 million in 2009.

Thomas F. Darden, Chairman of the Board of Quicksilver and beneficial owner of greater than a 10% interest in Quicksilver, was a member of our General Partner's board of directors during 2011. Philip Cook, Senior Vice President and Chief Financial Officer of Quicksilver, is a current member of our General Partner's board of directors. Because of Messrs. Darden and Cook's service on our General Partner's board of directors, Quicksilver qualifies as a related party.

We entered into a number of other agreements with Quicksilver prior to the Crestwood Transaction. A description of those agreements follows:

Secondment Agreement — Quicksilver and our General Partner had a services and secondment agreement pursuant to which specified employees of Quicksilver had been seconded to our General Partner to provide operating, routine maintenance and other services with respect to the assets owned or operated by us. We reimbursed Quicksilver for the services provided by the seconded employees. We reimbursed Quicksilver $7.6 million and $9.7 million for the services provided by the seconded employees for the years ended 2010 and 2009, respectively. There were no such reimbursements made in 2011. The Secondment Agreement was terminated with Quicksilver upon completion of the Crestwood Transaction.

Subordinated Note — On August 10, 2007, we executed the Subordinated Note payable to Quicksilver in the principal amount of $50 million. Our Credit Facility required us to terminate the Subordinated Note through the issuance of additional common units during the fourth quarter of 2010. See Note 10 — "Long-Term Debt" for a more detailed description of the note.

Distributions — We paid distributions to Quicksilver of $30.3 million and $27.0 million during 2010 and 2009, respectively. There were no such distributions made in 2011.

Allocation of costs — Prior to the closing of the Crestwood Transaction, the individuals supporting our operations were employees of Quicksilver. Our consolidated financial statements included costs allocated to us by Quicksilver for centralized general and administrative services performed by Quicksilver, as well as depreciation of assets utilized by Quicksilver's centralized general and administrative functions. Costs allocated to us were based on identification of Quicksilver's resources which directly benefited us and our estimated usage of shared resources and functions. All of the allocations were based on assumptions that management believed were reasonable. For the years ended 2010 and 2009 general and administrative expense includes cost allocated from Quicksilver of $2.0 million and $2.8 million, respectively.

Gas Gathering and Processing Agreements — Quicksilver has agreed to dedicate all of the natural gas produced on properties operated by Quicksilver within the areas served by our Alliance, Cowtown and Lake Arlington System through 2020. These dedications do not obligate Quicksilver to develop the reserves subject to these agreements.

Cowtown System — Effective September 1, 2008, we, together with Quicksilver, revised the previous agreement by specifying that Quicksilver has agreed to pay a fee per MMBtu for gathering, processing and compression of gas on the Cowtown System. The compression fee payable by Quicksilver at a gathering system delivery point shall never be less than our actual cost to perform such compression service. Quicksilver may also pay us a treating fee based on carbon dioxide content at the pipeline entry point. The rates are each subject to an annual inflationary escalation. We recognized $64.5 million, $62.4 million and $71.3 million in Revenue — related party during 2011, 2010 and 2009, respectively, related to this agreement.

During 2009, we entered into an agreement with Quicksilver to redeliver gas from the Cowtown Plant to a group of wells located near the facility. We recognized $1.1 million, $0.8 million and $0.9 million in Revenue — related party during 2011, 2010 and 2009, respectively, related to this agreement.

Quicksilver owns certain gathering pipelines connected to the Cowtown System. During 2009, we entered into an agreement with Quicksilver pursuant to which we operate certain of Quicksilver's gathering pipelines and gather natural gas from Quicksilver and other third-party customers utilizing Quicksilver's gathering pipelines. Under the agreement, we pay Quicksilver a fee based on the volume of third-party gas gathered through Quicksilver's pipelines. We recognized $0.2 million and $0.2 million in expense during 2011 and 2010, respectively, related to this agreement. There were no such expenses during 2009.

Lake Arlington System — During the fourth quarter of 2008, we completed the acquisition of the Lake Arlington System from Quicksilver for $42.1 million. In conjunction with the purchase, Quicksilver assigned its gas gathering agreement to us. Under the terms of the gas gathering agreement, Quicksilver agreed to allow us to gather all of the natural gas produced by wells that it operated and from future wells operated by it within the Lake Arlington area through 2020. Quicksilver's fee is subject to annual inflationary escalation. We recognized $22.6 million, $14.5 million and $13.7 million in Revenue — related party during 2011, 2010 and 2009, respectively, related to this agreement.

Alliance System — In June 2009, we entered into an agreement with Quicksilver by which we waived our right to purchase midstream assets located in northern Tarrant and southern Denton Counties, Texas. The agreement permitted Quicksilver to own and operate the Alliance System and granted us an option to purchase the Alliance System and additional midstream assets located in southern Denton and northern Tarrant Counties, Texas. During January 2010, we completed the purchase of the Alliance System for $84.4 million from Quicksilver ("Alliance Acquisition"). Due to Quicksilver's control of the Partnership through its ownership of the General Partner at the time of the Alliance Acquisition, the Alliance Acquisition was considered a transfer of net assets between entities under common control. As a result, we were required to revise our 2009 financial statements to include the financial results and operations of the Alliance System. Under the terms of that agreement, Quicksilver agreed to allow us to gather all of the natural gas produced by wells that it operated and from future wells operated by it within the Alliance area through 2020. We recognized $43.0 million and $27.5 million in Revenue — related party during 2011 and 2010, respectively, related to this agreement.

Concurrent with the Alliance Acquisition we also entered into an agreement with Quicksilver to lease pipeline assets attached to the Alliance System. We recognized $0.5 million and $2.2 million of expense related to this agreement during 2011 and 2010, respectively.

Hill County Dry System — In November 2009, Quicksilver and our General Partner mutually agreed to waive both parties' rights and obligations to transfer ownership of the HCDS from Quicksilver to us, which we refer to as the Repurchase Obligation Waiver. The Repurchase Obligation Waiver caused derecognition of the assets and liabilities directly attributable to the HCDS, most significantly the property, plant and equipment and repurchase obligation, beginning in November 2009. The difference of $8.9 million between the assets' carrying values and the liabilities was reflected as an increase in partners' capital effective upon the decision not to purchase. In addition, the Repurchase Obligation Waiver caused the elimination of the HCDS' revenues and expenses from our consolidated results of operations beginning in November 2009. The revenues and expenses directly attributable to the HCDS for the period prior to November 2009 have been retrospectively reported as discontinued operations. We operated the HCDS pursuant to an operating agreement with Quicksilver effective as of the Crestwood Transaction and ended in October 2011. We recognized $0.5 million and $0.1 million during 2011 and 2010, respectively, related to this agreement.

Other Agreements — During 2010 we entered in an agreement with Quicksilver to lease office space in Glen Rose, Texas. We recognized $87,000 and $22,000 in expense during 2011 and 2010, respectively, related to this agreement.

Crestwood Transaction — The Crestwood Transaction was funded by an equity contribution from funds managed by Crestwood Holdings and a $180 million senior secured term loan obtained by Crestwood Holdings payable to multiple financial investors. Crestwood Holdings' ownership in us is pledged as collateral and is dependent on distributions from us to service the debt obligation which is not included in our financial position.

Under the agreements governing the Crestwood Transaction, Quicksilver and Crestwood Holdings have agreed for two years not to solicit each other's employees and Quicksilver has agreed not to compete with us with respect to gathering, treating and processing of natural gas and the transportation of NGL in Denton, Hood, Somervell, Johnson, Tarrant, Parker, Bosque and Erath Counties in Texas. Quicksilver is entitled to appoint a director to our General Partner's board of directors until the later of the second anniversary of the closing or such time as Quicksilver generates less than 50% of our consolidated revenue in any fiscal year. Pursuant to this provision, Quicksilver has designated Philip Cook to our General Partner's board of directors.

In connection with the closing of the Crestwood Transaction, Quicksilver provided us with transitional services on a temporary basis on customary terms. More than 100 employees who had previously been seconded to us from Quicksilver became employees of Crestwood Holdings. We also entered into an agreement with Quicksilver for the joint development of areas governed by certain of our existing commercial agreements and amended certain of our existing commercial agreements, most significantly to extend the terms of all Quicksilver gathering agreements to 2020 and to establish a fixed gathering rate on the Alliance System. During 2011 and 2010, we have recognized $0.5 million and $0.4 million, respectively, related to the transitional services agreement and $1.5 million and $0.2 million, respectively, related to the joint operating agreement.

17. PARTNERS' CAPITAL AND DISTRIBUTIONS

Class C and Common Unit Offerings

On April 1, 2011, we issued 6,243,000 Class C units, representing limited partner interests, in a private placement. The negotiated purchase price for the Class C units was $24.50 per unit, resulting in net proceeds to us of approximately $153 million which was used to finance a portion of our Frontier Gas Acquisition. The Class C units are substantially similar in all respects to our existing common units, representing limited partner interests, except that we can elect to pay distributions for our Class C units through the issuance of additional Class C units or cash. The Class C units will convert into common units on a one-for-one basis on the second anniversary of the date of issuance.

In connection with the issuance of the Class C units, our General Partner made an additional capital contribution of $8.7 million to us in exchange for the issuance of an additional 293,948 General Partner units, increasing the General Partner interest to 2%.

On May 4, 2011, we completed a public offering of 1,800,000 common units, representing limited partner interests at a price of $30.65 per common unit ($29.75 per common unit, net of underwriting discounts and commissions), providing net proceeds of approximately $53 million. The net proceeds from the offering were used to reduce indebtedness under our Credit Facility and for general partnership purposes. In connection with the issuance of the common units, our General Partner did not make an additional capital contribution resulting in a dilution of the General Partner's interest to approximately 1.9%.

Partnership Agreement

Our Second Amended and Restated Agreement of Limited Partnership, dated February 19, 2008, as amended ("Partnership Agreement"), requires that, within 45 days after the end of each quarter, we distribute all of our available cash to unitholders of record on the applicable record date, as determined by our General Partner.

The term "available cash," for any quarter, consists of all cash on hand at the end of that quarter:

- *less* the amount of cash reserves established by our General Partner to:
    - comply with applicable law, any of our debt instruments or other agreements; or
    - provide funds for distribution to our unitholders and to our General Partner for any one or more of the next four quarters;
- *plus*, if our General Partner so determines, all or a portion of cash on hand on the date of determination of available cash for the quarter resulting from working capital borrowings made subsequent to the end of such quarter; and

- *plus*, if our General Partner so determines, all or a portion of available working capital borrowings on the date of determination of available cash for such quarter.

Working capital borrowings are generally borrowings that are made under a credit facility or another arrangement, are used solely for working capital purposes or to pay distributions to unitholders and are intended to be repaid within 12 months. Available working capital borrowings means on the date of determination any amounts available to be borrowed as working capital borrowings.

Minimum Quarterly Distribution. We intend to distribute to the holders of our common units on a quarterly basis at least the minimum quarterly distribution of $0.30 per unit, or $1.20 per year, to the extent we have sufficient cash from our operations after establishment of cash reserves and payment of fees and expenses, including payments to our General Partner. However, there is no guarantee that we will pay the minimum quarterly distribution on the units in any quarter. Even if our cash distribution policy is not modified or revoked, the amount of distributions paid under our policy and the decision to make any distribution is determined by our General Partner, taking into consideration the terms of our Partnership Agreement. We will be prohibited from making any distributions to unitholders if it would cause an event of default or an event of default exists, under our Credit Facility or other agreements governing our debt.

General Partner Interest and Incentive Distribution Rights. Our General Partner is currently entitled to 1.74% of all quarterly distributions that we make prior to our liquidation. As of February 13, 2012 our General Partner interest is represented by 763,892 General Partner units. Our General Partner has the right, but not the obligation, to contribute a proportional amount of capital to us to maintain its current General Partner interest. The General Partner's 1.74% interest in these distributions will be reduced if we issue additional units in the future and our General Partner does not contribute a proportional amount of capital to us to maintain its 1.74% General Partner interest.

Our General Partner also currently holds incentive distribution rights ("IDR") that entitle it to receive increasing percentages, up to a maximum of 49.74% of the cash we distribute from operating surplus in excess of $0.45 per unit per quarter. The maximum distribution of 49.74% includes distributions paid to our General Partner on its 1.74% General Partner interest and assumes that our General Partner maintains its General Partner interest at 1.74%. The maximum distribution of 49.74% does not include any distributions that our General Partner may receive on limited partner units that it owns.

The following table presents distributions for 2011 and 2010 (In millions, except per unit data):

			Distribution Paid					
			Limited Partners		General Partner			
Payment Date	**Attributable to the Quarter Ended**	**Per Unit Distribution**	**Common**	**Paid-In-Kind Value to Class C unitholders**	**General Partner interest and IDR**	**Paid-In-Kind Value to Class C unitholders**	**Total Cash**	**Total Distribution**
2012								
February 10, 2012	December 31, 2011	$0.49	$17.9	$ 3.2	$2.8	$ 0.5	$20.7	$24.4
2011								
November 10, 2011	September 30, 2011	$0.48	$15.8	$ 3.1	$2.3	$ 0.4	$18.1	$21.6
August 12, 2011	June 30, 2011	$0.46	$15.2	$ 2.9	$1.6	$ 0.2	$16.8	$19.9
May 13, 2011	March 31, 2011	$0.44	$13.7	$ 2.7	$1.1	$ 0.2	$14.8	$17.7
February 11, 2011	December 31, 2010	$0.43	$13.4	$—	$0.9	$—	$14.3	$14.3
2010								
November 12, 2010	September 30, 2010	$0.42	$13.1	$—	$0.8	$—	$13.9	$13.9
August 13, 2010	June 30, 2010	$0.42	$12.0	$—	$0.7	$—	$12.7	$12.7
May 14, 2010	March 31, 2010	$0.39	$11.1	$—	$0.5	$—	$11.6	$11.6

Cash distributions include amounts paid to common and subordinated unitholders. Beginning with the distributions for the quarter ended December 31, 2010, we no longer have any subordinated units due to the conversion of all subordinated units into common units. See Note 1 — "Organization and Description of Business" for a description of our conversion of the subordinated units. We have the option to pay distributions to our Class C unitholders with cash or by issuing additional Paid-In-Kind Class C units based upon the volume weighted-average price of our common units for the 10 trading days immediately preceding the date the distribution is declared. During 2011, we issued an aggregate 473,731 additional Class C units in quarterly distributions.

On April 28, 2011, a registration statement (No. 333-171735) providing for the issuance of up to $500 million of our common units, senior units, debt securities, warrants, purchase contracts or units was declared effective by the SEC. During 2011, we issued 1,800,000 of our common units in a public offering at a price of $30.65 per common unit ($29.50 per common unit net of underwriting costs). At December 31, 2011, the registration statement had remaining capacity allowing for the issuance of up to approximately $444.8 million of securities. After the January 2012 public offering of 3,500,000 common units at a price per unit of $30.73, the registration statement had remaining capacity allowing for the issuance of up to approximately $337.2 million of securities.

18. SUBSEQUENT EVENTS

Subsequent Equity Offering

On January 13, 2012, we completed a public offering of 3,500,000 common units representing limited partner interests in us, at a price of $30.73 per common unit ($29.50 per common unit, net of underwriting discounts), providing net proceeds of approximately $102.8 million. We used the net proceeds from the offering to reduce indebtedness under our Credit Facility. In connection with issuance of the common units, our General Partner did not make an additional capital contribution resulting in a reduction in our General Partner's general partner interest in us to approximately 1.74%.

Tygart Valley Pipeline

On December 13, 2011, we announced the signing of a Memorandum Of Understanding ("MOU") with Mountaineer Keystone LLC ("MK"), a related party, to construct a 16 inch natural gas gathering system of approximately 42 miles ("Tygart Valley Pipeline or TVP") to serve MK's Marcellus Shale development program in northeast West Virginia.

On February 22, 2012 we entered in to an amendment to the MOU ("MOU Amendment"), which extends the term of the MOU, including its exclusivity provisions, through January 31, 2013 ("Extension Period"). In addition to the Extension Period, the MOU Amendment provides that any requested reimbursement of Tygart Valley Pipeline ("TVP") project costs incurred by us during the Extension Period relating to the TVP project shall be limited to a cumulative total of $2.25 million except as otherwise approved in advance by MK.

Crestwood Marcellus Midstream LLC

Antero Acquisition

On February 24, 2012, we and Crestwood Holdings LLC, through a newly formed joint venture named Crestwood Marcellus Midstream LLC ("Joint Venture"), entered into a purchase agreement, dated as of February 24, 2012 ("Purchase Agreement"), with Antero Resources Appalachian Corporation ("Antero"), pursuant to which the Joint Venture will acquire certain of Antero's Marcellus Shale gathering system assets located in Harrison and Doddridge Counties, West Virginia for $375 million in cash plus an earn-out which would allow Antero to earn additional payments of up to $40 million based upon average annual production levels achieved during 2012 and 2013 ("Antero Acquisition"). Additionally, at closing, the parties have agreed to enter into a 20-year gas gathering and compression agreement, which will provide for an area of dedication of approximately

127,000 gross acres, or 104,000 net acres. The transaction will have a January 1, 2012 effective date and is expected to close in March 2012, subject to regulatory approvals and customary closing conditions.

In conjunction with the formation of the Joint Venture, we will contribute approximately $131 million, in exchange for a 35% membership interest in the Joint Venture and Crestwood Holdings LLC is obligated to contribute approximately $244 million in return for a 65% membership interest in the Joint Venture.

19. SEGMENT INFORMATION

Our operations include three reportable operating segments. These operating segments reflect the way we internally report the financial information used to make decisions and allocate resources in connection with our operations. We evaluate the performance of our operating segments based on EBITDA, which represents operating income plus, depreciation, amortization and accretion expense. Our business segments reflect the primary geographic areas in which we operate and consist of Barnett, Fayetteville, Granite Wash and Other, all of which are located within the United States of America. Other consists of those operating segments or reporting units that did not meet quantitative reporting thresholds. Each of our business segments are engaged in the gathering, processing, treating, compression, transportation and sales of natural gas and delivery of NGLs. Revenue-related party in our Barnett segment consists of revenues associated with a single customer greater than 10%.

The following tables summarize the reportable segment data as of and for the years ended December 31, 2011, 2010 and 2009 (In thousands):

	Year Ended December 31, 2011					
	Barnett	Fayetteville (1)	Granite Wash (1)	Other (2) (3)	Corporate	Total
Revenue	$ 8,859	$ 20,800	$38,213	$ 6,723	$ —	$ 74,595
Revenue - related party	131,225	—	—	—	—	131,225
Total revenues	$140,084	$ 20,800	$38,213	$ 6,723	$ —	$ 205,820
Operations and maintenance expense	25,147	8,992	1,499	665	—	36,303
Product purchases	—	1,302	33,245	4,240	—	38,787
General and administrative expense	—	—	—	—	24,153	24,153
Gain from exchange of property, plant and equipment	—	—	—	—	1,106	1,106
EBITDA	114,937	10,506	3,469	1,818	(23,047)	$ 107,683
Depreciation, amortization and accretion expense	24,395	6,941	1,600	847	29	33,812
Operating income (loss)	$ 90,542	$ 3,565	$ 1,869	$ 971	$(23,076)	$ 73,871
Goodwill	$ —	$ 76,767	$16,861	$ —	$ —	$ 93,628
Total assets	$545,656	$300,338	$77,313	$85,307	$ 18,278	$1,026,892
Capital Expenditures	$ 19,999	$ 17,757	$ 7,960	$ 2,041	$ 648	$ 48,405

(1) Includes nine months of operating income for Fayetteville and Granite Wash, from April 1, 2011 to December 31, 2011, subsequent to acquisition.

(2) Includes eleven months of operating income for Las Animas System, from February 1, 2011 to December 31, 2011, subsequent to acquisition.

(3) Includes two months of operating income for Sabine System, from November 1, 2011 to December 31, 2011, subsequent to acquisition.

	Year Ended December 31, 2010					
	Barnett	Fayetteville	Granite Wash	Other	Corporate	Total
Revenue	$ 8,355	$—	$—	$—	$ —	$ 8,355
Revenue - related party	105,235	—	—	—	—	105,235
Total revenues	$113,590	$—	$—	$—	$ —	$113,590
Operations and maintenance expense	25,702	—	—	—	—	25,702
General and administrative expense	—	—	—	—	17,657	17,657
EBITDA	87,888	—	—	—	(17,657)	$ 70,231
Depreciation, amortization and accretion expense	22,359	—	—	—	—	22,359
Operating income (loss)	$ 65,529	$—	$—	$—	$(17,657)	$ 47,872
Total assets	$557,163	$—	$—	$—	$ 13,464	$570,627
Capital Expenditures	$ 69,069	$—	$—	$—	$ —	$ 69,069

	Year Ended December 31, 2009					
	Barnett	Fayetteville	Granite Wash	Other	Corporate	Total
Revenue	$ 4,392	$—	$—	$—	$ —	$ 4,392
Revenue - related party	91,489	—	—	—	—	91,489
Total revenues	$ 95,881	$—	$—	$—	$ —	$ 95,881
Operations and maintenance expense	21,968	—	—	—	—	21,968
General and administrative expense	—	—	—	—	9,676	9,676
EBITDA	73,913	—	—	—	(9,676)	$ 64,237
Depreciation, amortization and accretion expense	20,829	—	—	—	—	20,829
Operating income (loss)	$ 53,084	$—	$—	$—	$ (9,676)	$ 43,408
Total assets	$484,683	$—	$—	$—	$ 2,941	$487,624
Capital Expenditures	$ 54,818	$—	$—	$—	$ —	$ 54,818

20. SELECTED QUARTERLY DATA (UNAUDITED)

The following presents a summary of selected quarterly data. Financial information has been revised to include the retroactive presentation of the Alliance Assets and revenues (In thousands, except per unit data).

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2011				
Revenues	$32,380	$55,535	$58,615	$59,290
Operating income	$12,604	$20,375	$20,505	$20,387
Net income	$ 9,376	$10,227	$13,058	$12,342
Basic income per unit:				
Net income per limited partner unit	$ 0.27	$ 0.22	$ 0.27	$ 0.24
Diluted income per unit:				
Net income per limited partner unit	$ 0.27	$ 0.22	$ 0.27	$ 0.24
2010				
Revenues	$24,739	$27,194	$30,366	$31,291
Operating income	$ 8,920	$13,131	$15,461	$10,360
Net income	$ 6,189	$10,113	$12,231	$ 6,339
Basic income per unit:				
Net income per limited partner unit	$ 0.20	$ 0.33	$ 0.40	$ 0.18
Diluted income per unit:				
Net income per limited partner unit	$ 0.20	$ 0.31	$ 0.38	$ 0.18

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

None.

Item 9A. Controls and Procedures

Disclosure Controls and Procedures

Disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934, as amended (“Exchange Act”)) are controls and other procedures that are designed to ensure that the information that we are required to disclose in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission’s (“SEC”) rules and forms, and that such information is accumulated and communicated to the management of Crestwood Gas Services GP LLC (“General Partner”), including the Chief Executive Officer and Chief Financial Officer of our General Partner, as appropriate to allow timely decisions regarding required disclosure.

On November 1, 2011, the Partnership acquired Tristate Sabine, LLC (“Tristate”). For purposes of determining the effectiveness of our disclosure controls and procedures and any change in our internal control over financial reporting, management has excluded Tristate from its evaluation of these matters. The acquired business represented approximately 7% of our consolidated total assets at December 31, 2011 and was approximately 1% of our consolidated total revenue for the year ended December 31, 2011.

In connection with the preparation of this annual report, the management of our General Partner, under the supervision and with the participation of the Chief Executive Officer and the Chief Financial Officer of our General Partner, carried out an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures as of December 31, 2011. Based on this evaluation, the Chief Executive Officer and Chief Financial Officer of our General Partner concluded that our disclosure controls and procedures were effective as of December 31, 2011.

Management’s Report on Internal Control Over Financial Reporting

Management of our General Partner, under the supervision and with the participation of our General Partner’s Chief Executive Officer and Chief Financial Officer, is responsible for establishing and maintaining adequate internal control over financial reporting as such term is defined in Rules 13a-15(f) under the Exchange Act.

Because of its inherent limitations, internal control over financial reporting and procedures may not prevent or detect misstatements. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, have been detected. 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 and procedures may deteriorate.

Under the supervision and with the participation of our General Partner’s Chief Executive Officer and Chief Financial Officer, our General Partner’s management conducted an assessment of our internal control over financial reporting as of December 31, 2011, based on the criteria established in Internal Control — Integrated Framework, issued by the Committee of Sponsoring Organizations of the Treadway Commission (“COSO”). Based on this assessment, our General Partner’s management has concluded that, as of December 31, 2011, our internal control over financial reporting was effective.

The effectiveness of our internal control over financial reporting as of December 31, 2011, has been audited by Deloitte & Touche LLP, our independent registered public accounting firm, and they have issued an attestation report expressing an unqualified opinion on the effectiveness of our internal control over financial reporting, as stated in their report included herein.

Material Weakness in Internal Control Over Financial Reporting

A material weakness is a deficiency, or a combination of deficiencies, in internal control over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act), such that there is a reasonable possibility that a material misstatement of the Company's annual or unaudited condensed consolidated interim consolidated financial statements will not be prevented or detected on a timely basis.

During fourth quarter of 2011, management became aware of a deficiency in controls relating to the preparation of pro forma financial information that is required to be disclosed in the footnotes to our condensed consolidated financial statements. We concluded that such a deficiency represented a material weakness in internal control over financial reporting. This material weakness resulted in the amendment to our Quarterly Report on Form 10-Q/A for the three months and nine months ended September 30, 2011, in order to restate the pro forma financial information.

Management's Remediation Efforts

The Partnership implemented additional controls during fourth quarter related to financial reporting disclosures for acquisitions and additional review procedures by individuals with expertise in generally accepted accounting principles in the United States and SEC financial reporting standards. These actions included, among other things, hiring an Interim Chief Accounting Officer and engaging third party accounting and internal control experts.

Management and the audit committee are fully committed to continued improvement of our internal controls over financial reporting. We have worked diligently on this matter and management believes that the process improvements, addition of accounting and internal control experts and modifications to controls made since the identified material weakness, have significantly strengthened our internal controls over financial reporting. We believe that our application of the above remediation efforts and stated improvements have fully remediated the material weakness in the controls over our pro forma disclosures.

Changes in Internal Control Over Financial Reporting

Other than described above, there have not been any other changes in the Partnership's internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) during the fourth fiscal quarter of the Partnership's fiscal year ended December 31, 2011 that have materially affected, or are reasonable likely to materially affect the Partnership's internal control over financial reporting.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Unitholders of
Crestwood Midstream Partners LP

We have audited the internal control over financial reporting of Crestwood Midstream Partners LP and subsidiaries (the "Partnership") as of December 31, 2011, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. As described in Management's Report on Internal Control Over Financial Reporting, management excluded from its assessment the internal control over financial reporting at Tristate Sabine, LLC, which was acquired on November 1, 2011 and whose financial statements constitute 7% of total assets and 1% of revenues of the consolidated financial statement amounts as of and for the year ended December 31, 2011. Accordingly, our audit did not include the internal control over financial reporting at Tristate Sabine, LLC. The Partnership'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. Our responsibility is to express an opinion on the Partnership's internal control over financial reporting based on our audit.

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

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

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

In our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2011, based on the criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2011 of the Partnership and our report dated February 29, 2012 expressed an unqualified opinion on those financial statements.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas

February 29, 2012

Item 9B. Other Information

None

PART III

Item 10. Directors, Executive Officers and Corporate Governance

Management of Crestwood Midstream Partners LP

As a limited partnership, we have no directors or officers. Instead, Crestwood Gas Services GP LLC ("General Partner") manages our operations. Our General Partner is not elected by our unitholders and is not subject to re-election in the future. The board of directors of our General Partner ("Board") oversees our operations. Unitholders are not entitled to elect the directors of our General Partner or directly or indirectly participate in our management or operations. However, our General Partner owes a fiduciary duty to our unitholders as defined and described in our Second Amended and Restated Agreement of Limited Partnership of Crestwood Midstream Partners LP ("CMLP"), dated February 19, 2008, as amended ("Partnership Agreement"). Our General Partner will be liable, as General Partner, for all of our debts (to the extent not paid from our assets), except for indebtedness or other obligations that are made specifically nonrecourse to it. Our General Partner, therefore, may cause us to incur indebtedness or other obligations that are nonrecourse to it.

The Board oversees our operations. Our General Partner currently has nine directors on the Board. Crestwood Gas Services Holdings LLC, the sole member of our General Partner, elects all members to the Board and our General Partner has three directors that are independent as defined under the independence standards established by the New York Stock Exchange ("NYSE"). The NYSE does not require a listed limited partnership like us to have a majority of independent directors on the Board or to establish a compensation committee or a nominating/corporate governance committee.

All of our executive management personnel are employees of Crestwood Holdings Partners, LLC and its affiliates ("Crestwood Holdings") and devote their time as needed to conduct our and Crestwood Holdings' business and affairs. These officers of Crestwood Holdings manage the day-to-day affairs of our business. Because Crestwood Holdings' only cash generating assets are direct and indirect partnership interests in us, we expect that our executive officers will devote a substantial majority of their time to our business, as was the case in 2011. We expect the amount of time that the executive management personnel of our General Partner devote to our business in future periods to be driven by the needs and demands of our ongoing business and business development efforts, which are likely to increase as our asset base and operations increase in size. However, depending on how our business develops and the nature of the business development efforts by executive management, the amount of time that the executive management team of our General Partner devotes to our business may increase or decrease in future periods. We also utilize a significant number of employees of Crestwood Holdings to operate our business and provide us with general and administrative services. We reimburse Crestwood Holdings for all expenses of operational personnel who perform services for our benefit, all general and administrative expenses and certain direct expenses. See Item 13, "Certain Relationships and Related Transactions, and Director Independence — Omnibus Agreement" for more information.

Directors and Executive Officers

The following information is provided with respect to the directors and executive officers of Crestwood Gas Services GP LLC as of February 13, 2012.

Name	Age	Position
Robert G. Phillips	57	President, Chief Executive Officer and Chairman of the Board
William G. Manias	49	Senior Vice President - Chief Financial Officer
Joel D. Moxley	53	Senior Vice President - Chief Operating Officer
Steven A. Stophel	51	Interim Chief Accounting Officer
Kelly J. Jameson	47	Senior Vice President - General Counsel and Corporate Secretary
S. Eric Guy	41	Vice President and Controller
Robert T. Halpin	28	Vice President - Business Development
Mark G. Stockard	45	Vice President - Investor Relations and Treasurer
Alvin Bledsoe	63	Director
Philip W. Cook	50	Director
Timothy H. Day	41	Director
Michael G. France	34	Director
Philip D. Gettig	66	Director
Joel C. Lambert	43	Director
J. Hardy Murchison	40	Director
John W. Somerhalder II	56	Director

Although the limited liability company agreement of our General Partner provides flexibility in the directors' length of service, we anticipate that the sole member of our General Partner, Crestwood Gas Services Holdings LLC, will appoint directors annually to serve until the earlier of their death, resignation, retirement, disqualification or removal. Officers serve at the discretion of the Board. The following biographies describe the business experience of the directors and executive officers of the General Partner. Also presented below is information regarding each director's experience, qualifications, attributes and skills that led Crestwood Gas Services Holdings LLC to the conclusion that each should serve as a director.

Robert G. Phillips, was elected Chairman, President and Chief Executive Officer of our General Partner in October 2010 and has served on the Management Committee of Crestwood Holdings since May 2010. Since November 2007, he has served as Chairman, President and CEO of Crestwood Midstream Partners, LLC. Previously, Mr. Phillips served as President and Chief Executive Officer and a Director of Enterprise Products Partners L.P. from February 2005 until June 2007 and Chief Operating Officer and a Director of Enterprise Products Partners L.P. from September 2004 until February 2005. Mr. Phillips also served on the Board of Directors of Enterprise GP Holdings L.P., the general partner of Enterprise Products Partners L.P., from February 2006 until April 2007. He previously served as Chairman of the Board and CEO of GulfTerra Energy Partners, L.P. ("GTM"), from 1999-2004, prior to GTM's merger with Enterprise Product Partners, LP, and held senior executive management positions with El Paso Corporation, a natural gas and related energy products provider and one of North America's largest independent natural gas producers, including President of El Paso Field Services from 1996-2004. Prior to that he was Chairman, President and CEO of Eastex Energy, Inc. from 1981-1995. Mr. Phillips is an Advisory Director of Triten Corporation, a leading international engineering firm and alloy products manufacturer. Mr. Phillips was selected to serve as the Chairman of the Board of our General Partner because of his deep experience in the midstream business, expansive knowledge of the oil and gas industry, as well as his experience in executive leadership roles for public companies in the energy industry and operational and financial expertise in the oil and gas business generally.

William G. Manias, was appointed Senior Vice President and Chief Financial Officer of our General Partner in October 2010. Prior to joining our General Partner, Mr. Manias was Chief Financial Officer of Crestwood Midstream Partners, LLC from October 2009 through September 2010. From January 2006 through January 2009, Mr. Manias was the Chief Financial Officer of TEPPCO Partners, LP. Prior to TEPPCO, he served as Vice

President of Business Development and Strategic Planning at Enterprise Product Partners, LP. From February 2004 to September 2004, he was Vice President and Chief Financial Officer of GulfTerra Energy Partners. Mr. Manias holds a Bachelor of Science in Civil Engineering from Princeton University, Masters in Petroleum Engineering and a Masters of Business Administration from Rice University.

Joel D. Moxley was appointed Senior Vice President and Chief Operating Officer of our General Partner in October 2010. From April 2008 until joining our General Partner, Mr. Moxley was Senior Vice President of Crestwood Midstream Partners, LLC. From November 2005 to March 2008, he was Senior Vice President of Crosstex Energy, L.P. From September 2004 to November 2005, Mr. Moxley was a Senior Vice President for Enterprise Products Partners, L.P. From January 2001 to August 2004 he was Vice President of El Paso Corporation, a natural gas and related energy products provider and one of North America's largest independent natural gas producers. From 1997 to 2000 he was a Vice President for PG&E Corporation. Mr. Moxley holds a Bachelor of Science in Chemical Engineering from Rice University.

Steven A. Stophel was appointed interim Chief Accounting Officer (Principal Accounting Officer) of our General Partner in December 2011. Mr. Stophel joined Alvarez & Marsal in 2011 and serves as a senior director specializing in post-merger financial integration, business and financial process improvement, SEC financial reporting and compliance, public listing readiness and complex accounting matters. Prior to joining Alvarez & Marsal, Mr. Stophel held senior positions in the international consulting and public accounting firms of Opportune LLP (2010-2011), KPMG LLP (2006-2010) and Arthur Andersen LLP (1989-1999). Mr. Stophel was the Chief Financial Officer for Reuters (CIS) in the Former Soviet Union (2001 – 2005) and Director of Finance of Russian Telecommunications Development Corporation (MediaOne International's subsidiary in Russia) (1999-2001). Mr. Stophel earned a bachelor degree in accounting from Regis University and is a Certified Public Accountant in Colorado and a Certified Internal Auditor. He is a member of the Colorado Society of CPAs, the American Institute of CPAs and the Institute of Internal Auditors.

Kelly J. Jameson, was appointed Senior Vice President, General Counsel and Corporate Secretary of our General Partner in October 2010. Prior to joining our General Partner, Mr. Jameson was employed by TransCanada Corporation from 2007 through October 2010, and was Senior Counsel and Corporate Secretary for the U.S. subsidiaries of TransCanada Corporation. From 1996 to February 2007, he was employed by El Paso Corporation, a natural gas and related energy products provider and one of North America's largest independent natural gas producers, and was Senior Counsel and Assistant Corporate Secretary. Mr. Jameson has a B.B.A. from Southern Methodist University and a Juris Doctorate from Oklahoma City University.

S. Eric Guy, was appointed Vice President and Controller of our General Partner in October 2010. Prior to joining our General Partner, Mr. Guy was Controller for Quicksilver Gas Services GP LLC and served in various financial roles with Quicksilver Resources Inc., an independent oil and gas company, since 2001. He began his career with KPMG LLP. Mr. Guy holds a B.B.A. from Baylor University and a Master of Business Administration from Texas Christian University.

Robert T. Halpin was appointed Vice President, Business Development of our General Partner in January 2012. Prior to joining our General Partner, Mr. Halpin was an Associate at First Reserve Corporation, a private equity company which invests exclusively in the energy industry, from July 2009 to January 2012. From July 2007 through June 2009, he was a Financial Analyst in the Global Natural Resources Group at Lehman Brothers. Mr. Halpin holds a B.B.A from The University of Texas at Austin.

Mark G. Stockard was appointed Vice President, Treasurer and Assistant Secretary of our General Partner in October 2010. Prior to joining our General Partner, Mr. Stockard was Director of Financial Planning and Investor Relations at Buckeye Partners, LP from October 2009 to September 2010. From 2002 through October 2009 he was Treasurer of TEPPCO Partners, LP. Mr. Stockard holds a B.B.A from Texas A&M University.

Alvin Bledsoe was elected director of our General Partner in July 2007. Since June 2011, Mr. Bledsoe has been a director and chair of the Audit Committee of SunCoke Energy, Inc. Prior to his retirement in 2005, Mr. Bledsoe served as a certified public accountant for 33 years at PricewaterhouseCoopers ("PwC"). From 1978 to 2005, he was a senior client engagement and audit partner for large, publicly-held energy, utility, pipeline, transportation and manufacturing companies. From 1998 to 2000, Mr. Bledsoe served as Global Leader of PwC's Energy, Mining and Utilities Industries Assurance and Business Advisory Services Group, and from 1992 to 2005 as a Managing Partner and Regional Managing Partner. During his career, Mr. Bledsoe also served as a member of PwC's governing body. Mr. Bledsoe was selected to serve as a director of our General Partner due to his extensive background in public accounting and auditing, including experience advising publicly-traded energy companies.

Philip W. Cook was elected director of our General Partner in September 2011. Since 2005, Mr. Cook has served as Senior Vice President — Chief Financial Officer of Quicksilver Resources Inc. From October 2004 until October 2005, Mr. Cook served as President and Chief Financial Officer of a private chemical company. From August 2001 until September 2004, he served as Vice President and Chief Financial Officer of a private oilfield service company. From August 1993 to July 2001, he served in various capacities, including Vice President and Controller, Vice President and Chief Information Officer and Vice President of Audit, of Burlington Resources Inc. (subsequently merged with ConocoPhillips), a public independent oil and gas company engaged in exploration, development, production and marketing. Mr. Cook also has nine years of experience in public accounting with Coopers & Lybrand. Mr. Cook was elected to serve as a director of our General Partner due to his depth of knowledge of us, including our history, development, contracts and relationships, his years of experience in the oil and gas industry and his positions as an executive of Quicksilver, our largest producer customer.

Timothy H. Day was elected director of our General Partner in October 2010. Since 2000, Mr. Day served as a Managing Director of First Reserve Corporation, a private equity company which invests exclusively in the energy industry. Additionally, Mr. Day has served on the Management Committee of Crestwood Holdings since May 2010. Prior to joining First Reserve Corporation, Mr. Day worked with SCF Partners for three years and prior to that he worked for three years with Credit Suisse First Boston and Salomon Brothers. Mr. Day previously served as a director of Chart Industries, Inc. (Nasdaq: GTLS), (also serving on the Audit, Compensation and Nominating and Corporate Governance Committees), and Pacific Energy Partners (NYSE: PPX). Mr. Day holds a B.B.A. from the University of Texas at Austin and a Master of Business Administration from Harvard Business School. Mr. Day was elected to serve as a director of our General Partner due to his years of experience in financing energy related companies including significant energy investment experience at First Reserve and his general knowledge of midstream and downstream energy companies.

Michael G. France was elected director of our General Partner in October 2010. Since 2007, Mr. France has served as a Director of First Reserve Corporation, a private equity company which invests exclusively in the energy industry. Additionally, Mr. France has served on the Management Committee of Crestwood Holdings since May 2010. From 2003 to 2007, Mr. France served as a Vice President in the Natural Resources Group, Investment Banking Division, at Lehman Brothers. From 1999 to 2001, he served as a Senior Consultant at Deloitte & Touche LLP. Mr. France holds a B.B.A. (cum laude) in Finance from the University of Texas at Austin and a Master of Business Administration from Jones Graduate School of Management at Rice University. Mr. France was elected to serve as a director of our General Partner due to his years of experience in financing energy related companies including his energy investment experience at First Reserve and his general knowledge of upstream and midstream energy companies.

Philip D. Gettig was elected director of our General Partner in July 2007. From February 2000 to December 2005, Mr. Gettig served as the Vice President, General Counsel and Secretary of Prism Gas Systems I, L.P. ("Prism"), a natural gas gathering and processing company that was purchased by Martin Midstream Partners L.P., a publicly-traded limited partnership, in November 2005. From 1981 to 1999, Mr. Gettig held various positions in the law department of Union Pacific Resources Company (UPR), a publicly traded exploration and production company with substantial natural gas gathering, processing and marketing operations. Positions held by Mr. Gettig included Managing Senior Counsel from 1996 to 1999. Mr. Gettig also served as General Counsel of Union Pacific Fuels, Inc., UPR's wholly-owned gathering, processing and marketing affiliate, from 1996 to 1999. After his retirement from Prism in 2005, he has provided consulting and legal services to Prism and he has also provided such services to individuals and small businesses. Mr. Gettig was selected to serve as a director of our General Partner due to his 30 years of legal experience within the oil and gas industry.

Joel C. Lambert was elected director of our General Partner in October 2010. Since 2007, Mr. Lambert has served as Associate General Counsel of First Reserve Corporation, a private equity company which invests exclusively in the energy industry. From 1998 to 2006, Mr. Lambert was an attorney in the Business and International Section of Vinson & Elkins LLP. In 1997, he was an Intern at the Texas Supreme Court, and has served as a Military Intelligence Specialist for the United States Army. Mr. Lambert holds a Bachelor of Environmental Design (Magna Cum Laude) from Texas A&M University and a Juris Doctorate from the University of Texas School of Law. Mr. Lambert was elected to serve as a director of our General Partner due to his years of legal experience within the energy industry and his general knowledge of midstream energy companies.

J. Hardy Murchison was elected as director of our General Partner in October 2010. Mr. Murchison is President of Encino Energy, LLC, a private oil and gas exploration and production company. Mr. Murchison was a Managing Director of First Reserve Corporation, a private equity company which invests exclusively in the energy industry from 2001 through 2011. Prior to that, he was Vice President of Corporate Development at Range Resources Corporation, an independent oil and gas company. He began his career at Simmons & Company International. Mr. Murchison holds a B.A. from the University of Texas at Austin and a Master of Business Administration from Harvard Business School. Mr. Murchison was elected to serve as a director of our General Partner due to his years of experience in financing energy related companies including significant energy investment experience at First Reserve and his general knowledge of upstream energy companies.

John W. Somerhalder II was elected director of our General Partner in July. Mr. Somerhalder has served as the President, Chief Executive Officer and a director of AGL Resources Inc. ("AGL Resources"), a publicly-traded energy services holding company whose principal business is the distribution of natural gas, since March 2006 and as Chairman of the Board of AGL Resources since November 2007. From 2000 to May 2005, Mr. Somerhalder served as the Executive Vice President of El Paso Corporation, a natural gas and related energy products provider and one of North America's largest independent natural gas producers, where he continued service under a professional services agreement from May 2005 to March 2006. From 2001 to 2005, he served as the President of El Paso Pipeline Group. From 1996 to 1999, Mr. Somerhalder served as the President of Tennessee Gas Pipeline Company, an El Paso subsidiary company. From April 1996 to December 1996, Mr. Somerhalder served as the President of El Paso Energy Resources Company. From 1992 to 1996, he served as the Senior Vice President, Operations and Engineering, of El Paso Natural Gas Company. From 1990 to 1992, Mr. Somerhalder served as the Vice President, Engineering of El Paso Natural Gas Company. From 1977 to 1990, Mr. Somerhalder held various other positions at El Paso Corporation and its subsidiaries until being named an officer in 1990. Mr. Somerhalder was selected to serve as a director of our General Partner due to his years of experience in the oil and gas industry and his extensive business and management expertise, including as President, Chief Executive Officer and a director of a publicly-traded energy company.

Committees of the Board of Directors

The NYSE does not require its listed limited partnerships to have a compensation committee or a nominating and governance committee. Accordingly, each director of our General Partner may participate in the consideration of nomination and governance matters. Compensation matters relating to our executives and directors are reviewed and determined by the Management Committee of Crestwood Holdings.

Our General Partner's board of directors has established an audit committee. The audit committee consists of Messrs. Bledsoe, Gettig and Somerhalder, with Mr. Bledsoe acting as the chairman of the audit committee. Our General Partner's board of directors has determined that each of the members of the audit committee meets the independence and experience standards established by the NYSE and the Exchange Act and that Mr. Bledsoe is an "audit committee financial expert" within the meaning of SEC rules. The audit committee assists the board of directors in its oversight of the integrity of our financial statements and our compliance with legal and regulatory requirements and corporate policies and controls. The audit committee has the sole authority to retain and terminate our independent registered public accounting firm, approve all auditing services and related fees and the terms thereof, and pre-approve any non-audit services to be rendered by our independent registered public accounting firm. The audit committee is also responsible for confirming the independence and objectivity of our independent registered public accounting firm.

Our General Partner's board of directors has also established a conflicts committee. The conflicts committee consists of Messrs. Bledsoe, Gettig and Somerhalder, with Mr. Gettig acting as the chairman of the conflicts committee, and is charged with reviewing specific matters that our General Partner's board of directors believes may involve conflicts of interest. Any matters approved by the conflicts committee will be conclusively deemed to be fair and reasonable to us, to have been approved by all of our unitholders, and not to involve a breach of any duties that may be owed to our unitholders.

The charters of audit committee and conflicts committee appear in the Company Overview section under Corporate Governance of our website at www.crestwoodlp.com.

Code of Business Conduct and Ethics

Our General Partner's board of directors has adopted a Code of Business Conduct and Ethics that applies to, among other persons, the principal executive officer, principal financial officer and principal accounting officer of our General Partner. A copy of this Code of Business Conduct and Ethics appears in the Corporate Overview section under Corporate Governance of our website at www.crestwoodlp.com. We intend to post any amendments to or waivers of our Code of Business Conduct and Ethics with respect to the directors or executive officers of our General Partner in the Corporate Governance section of our website.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Exchange Act requires the executive officers and directors of our General Partner, and persons who own more than 10% of our limited partner units, to file reports of ownership and changes in ownership with the SEC. The executive officers and directors of our General Partner and owners of more than 10% of our limited partner units are required by SEC rules to furnish us with copies of all Section 16(a) forms they file.

Based solely on a review of the copies of such forms furnished to us and written representations from the directors and executive officers of our General Partner, we believe that during 2011 all directors and executive officers of our General Partner and all owners of more than 10% of our common units were in compliance with all applicable Section 16(a) filing requirements.

Item 11. Executive Compensation

Compensation Discussion and Analysis

We do not directly employ any of the persons responsible for managing or operating our business. Instead, we are managed by our General Partner, the executive officers of which are also executive officers of Crestwood Holdings and are compensated by Crestwood Holdings in their capacities as such. The following table sets forth the name and title of the individuals who served during 2011 as the principal executive officer and principal financial officer of our General Partner and the three persons other than the principal executive officer and principal financial officer that constitute the most highly compensated executive officers of our General Partner who were serving in such capacity at the end of December 31, 2011. We refer to these five individuals as "named executive officers."

Name	Title
Robert G. Phillips	President, Chief Executive Officer and Chairman of the Board
William G. Manias	Senior Vice President - Chief Financial Officer
Joel D. Moxley	Senior Vice President - Chief Operating Officer
Kelly J. Jameson	Senior Vice President, General Counsel & Corporate Secretary
Mark G. Stockard	Vice President, Investor Relations and Treasurer

Compensation Methodology

Pursuant to the Omnibus Agreement, dated October 8, 2010, among our General Partner and Crestwood ("Omnibus Agreement"), Crestwood Holdings provides certain general and administrative services to us, and we are obligated to reimburse Crestwood Holdings for any expenses it incurs in conjunction with the performance of those services, including compensation and benefits provided by Crestwood Holdings to the named executive officers.

Although we pay an allocated portion of Crestwood Holdings' direct costs of providing compensation and benefits to the named executive officers, we have no direct control over such costs. Crestwood Holdings' Management Committee ("Management Committee"), comprised of Messrs. Day, France and Phillips, establishes the base salary, bonus and other elements of compensation for Crestwood Holdings' executive officers, and such determinations are not subject to approvals by the Board or any of its committees. For the named executive officers other than the Chief Executive Officer, the compensation and amounts of awards are determined based on the recommendations of the Chief Executive Officer and his evaluation of the performance of each named executive officer. Compensation and amounts of awards for the Chief Executive Officer are determined by the Management Committee with the abstention of Mr. Phillips.

In addition to compensation paid to the named executive officers by Crestwood Holdings, certain of the named executive officers are eligible to participate in our Third Amended and Restated 2007 Equity Plan ("2007 Equity Plan"), which is administered by the Board. In 2011, none of the named executive officers were granted awards under the 2007 Equity Plan.

Compensation Objectives

As we do not directly compensate the executive officers of our General Partner, we do not have any set compensation programs. The elements of Crestwood Holdings' compensation program as administered by the Management Committee and discussed below, along with Crestwood Holdings' other rewards, are intended to provide a total rewards package designed to yield competitive total cash compensation, drive performance and reward contributions in support of the businesses of Crestwood Holdings and its other affiliates, including us, for which the named executive officers perform services. Because Crestwood Holdings' only cash generating assets are direct and indirect partnership interests in us, we expect that our executive officers will devote a substantial majority of their time to our business, as was the case in 2011. We were allocated 100% of the base salaries and benefits provided by Crestwood Holdings to the named executive officers. For 2011, Crestwood Holdings allocated $2.6 million of these costs to us. In determining this amount, Crestwood Holdings considered the estimated amount of time that the named executive officers devoted to our business and affairs and the amounts of the compensation and benefits provided by Crestwood Holdings to them. Although we bear an allocated portion of Crestwood Holdings' costs of providing compensation and benefits to the named executive officers, we do not have control over such costs and do not establish or direct the compensation policies or practices of Crestwood Holdings. Additionally, as required under the 2007 Equity Plan, the Board participates in the determination of appropriate performance based criteria and goals for such plans.

Elements of Compensation. Crestwood Holdings' executive officer compensation package includes a combination of annual cash and long-term incentive compensation including awards under Crestwood Holdings' employee benefit plans and incentive units from Crestwood Holdings. Elements of compensation that the named executive officers may be eligible to receive from Crestwood Holdings consist of the following: (1) annual base salary; (2) discretionary annual cash bonus awards; (3) awards pursuant to Crestwood Holdings' employee benefit plans and our 2007 Equity Plan and (4) where appropriate, other compensation, including limited perquisites. Additionally, elements of long-term incentive compensation that certain named executive officers may be eligible to receive include incentive units from Crestwood Holdings, the cost of which is not allocated to Crestwood Holdings but play a key role in enabling our General Partner to attract, recruit, hire and retain qualified executive officers.

Annual Base Salary. Base salary is intended to provide fixed compensation to the named executive officers for their performance of core duties with respect to our General Partner, Crestwood Holdings and its affiliates, including us, and to compensate for experience levels, scope of responsibility and future potential. Base salaries are not intended to compensate individuals for extraordinary performance or for above average company performance. The base salaries of the named executive officers are reviewed on an annual basis, as well as at the time of promotion and other changes in responsibilities or market conditions.

Discretionary Annual Cash Bonus Awards. In addition to the annual base salary, the named executive officers may be eligible to receive discretionary annual cash awards that, if awarded, are paid in a lump sum near the end of the fiscal year. These cash awards are designed to provide the named executive officers with competitive incentives to help drive performance and promote achievement of Crestwood Holdings' and our business objectives.

Employee Benefit Plan Awards. The named executive officers may be eligible to receive awards pursuant to our 2007 Equity Plan, which is administered by the Management Committee with the participation of the Board to establish appropriate performance based criteria and goals and Crestwood Holdings' employee benefit plans. These employee benefit plan awards are designed to reward the performance of the named executive officers by providing annual incentive opportunities tied to our annual performance and that of Crestwood Holdings. In particular, these awards are provided to the named executive officers in order to provide competitive incentives to these executives who can significantly impact performance and promote achievement of our and Crestwood Holdings' business objectives.

Other Compensation. Crestwood Holdings generally does not pay for perquisites for any of the named executive officers. No perquisites are paid for services rendered to us. Crestwood Holdings provides a life insurance policy and long term disability policy for all of its employees including the named executive officers with the annual premiums being paid by Crestwood Holdings. Crestwood Holdings does not provide the named executive officers any greater allocation toward employee health insurance premiums than is provided for all other employees covered on the health benefits plan.

2007 Equity Plan

Our 2007 Equity Plan is designed to promote our interests by providing to directors, officers and selected employees and consultants of our General Partner or its affiliates incentive compensation based on our common units. Individuals that are selected to participate in the 2007 Equity Plan determined by the equity committee or the Board, as applicable, to receive an award and are (i) officers or other employees of our General Partner who perform services for us, our General Partner or one of our or its affiliates, (ii) consultants who perform services for us, our General Partner or one of our or its affiliates or (iii) members of the Board who are not employees of our General Partner or one of its affiliates.

The 2007 Equity Plan is administered by the Board or a committee thereof, (currently the Management Committee). Any such committee will not administer phantom unit awards granted to non-employee directors of the Board. The Board has the full authority and discretion to administer the 2007 Equity Plan and to take any action that is necessary or advisable in connection with its administration.

The 2007 Equity Plan authorizes the granting of options, restricted units, phantom units, unit appreciation rights, performance units and performance bonuses. The maximum number of our common units that may at any time be delivered or reserved for delivery under the 2007 Equity Plan is 750,000 common units. The total number of common units available under the 2007 Equity Plan will be adjusted to include units that relate to awards granted under the 2007 Equity Plan that (i) expire or are forfeited, (ii) are withheld or tendered in payment of the exercise price of an option or in satisfaction of the taxes required to be withheld in connection with any award granted under the 2007 Equity Plan or (iii) are subject to an appreciation right that are not transferred to a participant upon exercise of the appreciation right.

The 2007 Equity Plan may be amended from time to time by the Board, but may not be amended without further approval of our unitholders if such amendment would result in the plan no longer satisfying any applicable requirements of the principal national securities exchange on which the common units are traded or Rule 16b-3 of the Exchange Act. No amendment of any outstanding option to reduce the exercise price will be authorized without the further approval of our unitholders. Furthermore, no option will be cancelled and replaced with options having a lower option price without further approval of our unitholders.

Unless terminated earlier, the 2007 Equity Plan will terminate on July 24, 2017, after which no further awards may be made. The 2007 Equity Plan will continue to govern outstanding awards, and its termination will not adversely affect the terms of any outstanding award.

Change-in-Control Arrangements

In the event of a change-in-control as described in the 2007 Equity Plan, all of a named executive officer's equity-based awards that have been granted under the 2007 Equity Plan would vest immediately. The Board believes that this change-in-control arrangement aligns the interests of the named executive officers with those of our unitholders.

Employment Agreements

With the exception of Messrs. Stockard and Jameson, none of the named executive officers operate under employment agreements. Pursuant to a letter agreement dated September 7, 2010, between Mr. Stockard and Crestwood Holdings, Mr. Stockard became the Vice President, Investor Relations and Treasurer of our General Partner effective October 1, 2010. Pursuant to the terms of that agreement, Mr. Stockard will receive an annual base salary of $220,000. He will be eligible to receive an annual cash bonus of up to 50% of his base salary as determined by the Management Committee based upon his individual performance and the performance of Crestwood Holdings and us based on meeting annual financial goals and non-financial goals set by the Management Committee or the Board. Mr. Stockard will be issued an annual equity grant in the form of phantom units under the 2007 Equity Plan in an amount equal to 45% of his base salary. Mr. Stockard received an initial one-time equity grant of 4,042 restricted units under the 2007 Equity Plan, with distribution rights. In addition, Mr. Stockard was issued 20,000 incentive units in Crestwood Holdings.

Pursuant to a letter agreement dated September 10, 2010, between Mr. Jameson and Crestwood Holdings, Mr. Jameson became the Senior Vice President — General Counsel of our General Partner effective October 15, 2010. Pursuant to the terms of that agreement, Mr. Jameson will receive an annual base salary of $240,000. He will be eligible to receive an annual cash bonus of up to 50% of his base salary as determined by the Management Committee based upon his individual performance and the performance of Crestwood Holdings and us based on meeting annual financial goals and non-financial goals set by the Management Committee or the Board.

Compensation Committee Report

As our General Partner does not have a compensation committee, the Management Committee provides the oversight, administers and makes decisions regarding Crestwood Holdings' compensation policies and plans' with the exception of the 2007 Equity Plan which provides for the participation of the Board to establish appropriate performance based criteria and goals. Additionally, the Board generally reviews and discusses the Compensation Discussion and Analysis with the management of our General Partner as a part of our governance practices. Based on this review and discussion, the Board, with the concurrence of the Management Committee, has directed that the Compensation Discussion and Analysis be included in this report for filing with the SEC.

Members of the Board of Directors of Crestwood Gas Services GP LLC

Alvin Bledsoe | *Philip W. Cook*
Timothy H. Day | *Michael G. France*
Philip D. Gettig | *J. Hardy Murchison*
Joel C. Lambert | *Robert G. Phillips*
John. W. Somerhalder II

Summary Compensation Table

The following table sets forth certain information regarding the compensation provided by us in 2011, 2010 and 2009 to the (i) current Chief Executive Officer of our General Partner, (ii) the current Chief Financial Officer of our General Partner, and (iii) the three most highly-compensated executive officers of our General Partner who were serving in such capacity at the end of December 31, 2011. These five individuals are referred to as "named executive officers" in the tables that follow:

Name and Principal Position	Year	Salary	Bonus	Equity Awards (1)	Other (3)	Total
Robert G. Phillips (2)	2011	$455,000	$423,000	$ —	$15,881	$893,881
President, Chief Executive Officer and Chairman of the Board	2010	$100,000	$200,000	$ —	$ —	$300,000
William G. Manias (2)	2011	$256,000	$138,000	$ —	$10,534	$404,534
Senior Vice President - Chief Financial Officer	2010	$ 62,500	$125,000	$ —	$ —	$187,500
Joel D. Moxley (2)	2011	$289,000	$240,000	$ —	$11,998	$540,998
Senior Vice President - Chief Operating Officer	2010	$ 62,500	$125,000	$ —	$ —	$187,500
Kelly J. Jameson (2)	2011	$260,000	$132,500	$ —	$10,694	$403,194
Senior Vice President - General Counsel and Corporate Secretary	2010	$ 50,000	$ 30,000	$ —	$ —	$ 80,000
Mark G. Stockard (2)	2011	$225,500	$113,000	$ —	$16,620	$355,120
Vice President, Investor Relations and Treasurer	2010	$ 55,000	$ 27,500	$245,183	$ —	$327,683

(1) This column reports the aggregate grant date fair value of the phantom unit awards granted in 2011, 2010 and 2009 computed in accordance with Accounting Standards Codification ("ASC") Topic 718. Additional information regarding the calculation of these amounts is included in Part II, Item 8, "Financial Statements and Supplementary Data — Notes to the Financial Statements" — Note 2 — "Summary of Significant Accounting Policies" and Note 15 — "Equity Plan" of this report and our annual reports for the respective year end.

(2) This individual joined the General Partner effective October 2010. Consequently, the information presented for 2010 represents the period of October 2010 to December 2011.

(3) This column includes payments of 401(k) matching, life insurance premiums for all named executive officers and distributions paid on Mr. Stockard's restricted units.

Grants of Plan-Based Awards in 2011

There were no grants awarded to the named executive officers in 2011 under our 2007 Equity Plan.

Outstanding Equity Awards at Year-End 2011

The following table sets forth information regarding the holdings of phantom and restricted unit awards by the named executive officers at December 31, 2011. No options with regard to our units have been granted to our named executive officers.

	Equity Awards in Units	
Name	Number of Shares or Units of Stock That Have Not Vested	Market Value of Shares or Units of Stock That Have Not Vested [(1)]
Robert G. Phillips	— [(2)]	$ —
William G. Manias	— [(2)]	$ —
Joel D. Moxley	— [(2)]	$ —
Kelly J. Jameson	— [(2)]	$ —
Mark G. Stockard	9,044[(3)]	$287,057

(1) The market value of phantom unit awards is based on $31.74, the closing market price of CMLP common units on December 30, 2011.

(2) Did not receive units.

(3) One-third of these units will vest on January 15, 2012, 2013 and 2014, respectively.

Stock Vested in 2011

There were no units held by named executive officers that vested during 2011.

Potential Payments upon Termination or Change-in-Control

Upon a named executive officer's termination by reason of death or disability or upon a change-in-control as defined under the 2007 Equity Plan, as amended, such named executive officer's outstanding unvested equity awards granted under the 2007 Equity Plan, as amended, would immediately vest. The payments set forth in the table are based on the assumption that the event occurred on December 30, 2011, the last business day of 2011. The amounts shown in the table do not include payments and benefits that could be received by such individual from Crestwood Holdings.

	Equity Awards in Units [(1)]	
Name	Number of Shares or Units of Stock That Have Not Vested	Market Value of Shares or Units of Stock That Have Not Vested [(2)]
Robert G. Phillips	—	$ —
William G. Manias	—	$ —
Joel D. Moxley	—	$ —
Kelly J. Jameson	—	$ —
Mark G. Stockard	9,044	$287,057

(1) Includes phantom units that will be settled in units upon vesting.

(2) The market value of unit awards is based on $31.74, the closing market price of our common units on December 30, 2011.

Director Compensation for 2011

Directors of our General Partner who are also employees of Crestwood Holdings are not separately compensated for their services as directors. For the year ended December 31, 2011, each of our non-employee directors was entitled to receive a fee of $100,000, payable 50% in phantom units and 50% in cash (subject to their election to receive phantom units in lieu of some or all of the cash portion). Each of these phantom unit awards was granted under our 2007 Equity Plan and settles in units upon vesting.

The following table sets forth certain information regarding the compensation of the non-employee directors of our General Partner:

Name	Fees Earned or Paid in Cash (1)	Equity Awards (2)	Total
Alvin Bledsoe	$ —	$99,994(3)	$ 99,994
Philip W. Cook	$25,000	$25,010(4)	$ 50,010
Thomas F. Darden	$37,500	$49,997(5)	$ 87,497
Timothy H. Day	$50,000	$49,997(6)	$ 99,997
Michael G. France	$50,000	$49,997(6)	$ 99,997
Philip D. Gettig	$40,000	$60,008(7)	$100,008
Joel C. Lambert	$50,000	$49,997(6)	$ 99,997
J. Hardy Murchison	$50,000	$49,997(6)	$ 99,997
John W. Somerhalder II	$ —	$99,994(3)	$ 99,994

(1) This column reports the aggregate compensation earned in 2011 and paid in cash and excludes $50,000 each that Messrs. Bledsoe and Somerhalder and $10,000 that Mr. Gettig elected to receive in the form of phantom units. It includes $25,000 received by Mr. Cook after his appointment to the Board in September 2011.

(2) This column reports the grant date fair value of the phantom unit awards granted in 2011 computed in accordance with ASC Topic 718. Additional information regarding the calculation of these amounts is included in Part II, Item 8, "Financial Statements and Supplementary Data — Notes to the Financial Statements" — Note 2 — "Summary of Significant Accounting Policies" and Note 15 — "Equity Plan" of this report.

(3) The grant date fair value calculated for the 3,606 phantom units granted to both Messrs. Bledsoe and Somerhalder in 2011, including those phantom units they received in lieu of $50,000 in cash fees. As of December 31, 2011, both Messrs. Bledsoe and Somerhalder had 3,606 unvested phantom units.

(4) The grant date fair value calculated for the 1,020 phantom units granted to Mr. Cook in September 2011 upon his appointment to the Board. As of December 31, 2011, Mr. Cook had 1,020 unvested phantom units.

(5) The grant date fair value calculated for the 1,803 phantom units granted to Mr. Darden in 2011. In September 2011, Mr. Darden resigned from his position on the Board thereby forfeiting his grant of 1,803 phantom units. As of December 31, 2011, Mr. Darden had no unvested phantom units due to his resignation.

(6) The grant date fair value calculated for the 1,803 phantom units granted to each Messrs. Day, France, Lambert and Murchison in 2011. As of December 31, 2011, they each had 1,803 unvested phantom units.

(7) The grant date fair value calculated for the 2,164 phantom units granted to Mr. Gettig in 2011, including those phantom units he received in lieu of $10,000 in cash fees. As of December 31, 2011, Mr. Gettig had 2,164 unvested phantom units.

Compensation Committee Interlocks and Insider Participations

As previously discussed, the Board is not required to maintain, and does not maintain a compensation committee.

Mr. Robert G. Phillips, who serves as the President, Chief Executive Officer and Chairman of our General Partner, participated in his capacity as a director in the deliberations of the Management Committee concerning executive officer compensation. In addition, during that period, Mr. Phillips made recommendations on behalf of the management of our General Partner to the Management Committee regarding named executive officer compensation but abstained from any decisions regarding his compensation.

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

Crestwood Midstream Partners LP

The following table sets forth certain information regarding the beneficial ownership of our common units as of February 13, 2012 by:

- each person or entity known by us to beneficially own more than 5% of our common units;
- each named executive officer of Crestwood Gas Services GP LLC;
- each director of Crestwood Gas Services GP LLC; and
- all directors and executive officers of Crestwood Gas Services GP LLC as a group.

Unless otherwise indicated by footnote, the beneficial owner exercises sole voting and investment power over the units. The percentages of beneficial ownership are calculated on the basis of 36,538,228 common units and 6,716,730 Class C units outstanding as of February 13, 2012. The amounts and percentage of units beneficially owned are reported on the basis of regulations of the SEC governing the determination of beneficial ownership of securities. Under the rules of the SEC, a person is deemed to be a "beneficial owner" of a security if that person has or shares "voting power," which includes the power to vote or to direct the voting of such security, or "investment power," which includes the power to dispose of or to direct the disposition of such security. Except as indicated by footnote, the persons named in the table below have sole voting and investment power with respect to all units shown as beneficially owned by them, subject to community property laws where applicable.

Name of Beneficial Owner [1]	Common Units	Percentage of Common Units	Class C Units	Percentage of Class C Units	Percentage of Common and Class Units
Common					
Crestwood Holdings Partners, LLC [2] [4]	19,544,089	53.5%	43,747	*	45.3%
Crestwood Gas Services Holdings LLC [3] [4]	19,544,089	53.5%	43,747	*	45.3%
Kayne Anderson Capital Advisors, L.P. [5]	4,147,679	11.4%	—	—	9.6%
Tortoise Capital Advisors, LLC [6]	3,120,813	8.5%	—	—	7.2%
Alvin Bledsoe [7]	56,358	*	—	—	*
Philip W. Cook	340	*	—	—	*
Timothy H. Day	601	*	—	—	*
Michael G. France	601	*	—	—	*
Philip D. Gettig	15,894	*	—	—	*
Joel C. Lambert	601	*	—	—	*
J. Hardy Murchison	601	*	—	—	*
John W. Somerhalder II	29,098	*	—	—	*
Robert G. Phillips	—	—	—	—	*
William G. Manias	—	—	—	—	*
Joel D. Moxley	—	—	—	—	*
Kelly J. Jameson	—	—	—	—	*
Mark G. Stockard	4,784	*	—	—	*
Directors and executive officers as a group (16)	124,831	*	—	—	*

Name of Beneficial Owner (1)	Common Units	Percentage of Common Units	Class C Units	Percentage of Class C Units	Percentage of Common and Class Units
Class C					
AT MLP Fund LLC	—	—	534,437	8.0%	1.2%
Fiduciary Claymore MLP	—	—	741,668	11.0%	1.7%
Kayne Anderson MLP	—	—	1,134,312	16.9%	2.6%
The Northwestern Mutual Life	—	—	654,407	9.7%	1.5%
Tortoise Energy	—	—	1,003,435	14.9%	2.3%
Tortoise MLP Fund Inc.	—	—	1,439,705	21.4%	3.3%

* Indicates less than 1%

(1) Unless otherwise indicated, the contact address for all beneficial owners in this table is 717 Texas Avenue, Suite 3150, Houston, Texas 77002.

(2) Crestwood Holdings is the ultimate parent company of Crestwood Gas Services Holdings LLC and may, therefore, be deemed to beneficially own the units held by Crestwood Holdings.

(3) Crestwood Gas Services Holdings LLC, an indirect wholly owned subsidiary of Crestwood Holdings, owns a 100% interest in our General Partner and a 44.6% limited partner interest in us.

(4) Crestwood Holdings has shared voting power and shared investment power with Crestwood Holdings, Crestwood Holdings LLC, Crestwood Holdings II LLC, FR XI CMP Holdings LLC, FR Midstream Holdings LLC, First Reserve GP XI, L.P., First Reserve GP XI, Inc., and William E. Macaulay over 19,544,089 common units of Crestwood Midstream Partners LP. Crestwood Gas Services GP LLC, the sole general partner of CMLP, owns a 1.74% general partner interest and incentive distribution rights (which represent the right to receive increasing percentages of quarterly distributions in excess of specified amounts) in CMLP.

(5) According to a Schedule 13G/A filed by Kayne Anderson Capital Advisors, L.P. and Richard A. Kayne with the SEC on January 24, 2012, Kayne Anderson Capital Advisors, L.P. together with Richard A. Kayne has shared voting and dispositive power over 4,147,679 common units. The address of Kayne Anderson Capital Advisors, L.P. and Richard A. Kayne is 1800 Avenue of the Stars, Second Floor, Los Angeles, California 90067.

(6) According to a Schedule 13G/A filed by Tortoise Capital Advisors, LLC, with the SEC on February 17, 2012, Tortoise Capital Advisors, LLC has beneficial ownership and shared dispositive power over 3,120,813 common units. It has shared voting power over 3,047,768 of those units. The address of Tortoise Capital Advisors, LLC is 11550 Ash Street, Suite 300, Leawood, Kansas 66211.

(7) Includes 200 common units over which Mr. Bledsoe exercises shared investment power.

Equity Compensation Plan Information

The following table sets forth information as of December 31, 2011, with respect to common units that may be issued under our existing equity compensation plans.

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted-average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
	(a)	(b)	(c)
Equity compensation plans approved by security holders (1)	114,753	N/A(2)	633,211
Equity compensation plans not approved by security holders	—	—	—
Total	114,753	N/A(2)	633,211

(1) Consists of the 2007 Equity Plan.
(2) Only phantom units have been issued under the 2007 Equity Plan. Each phantom unit entitles the holder to receive one common unit (or an amount in cash equal to the fair market value thereof) with respect to each phantom unit at vesting. Accordingly, without payment of cash, there is no reportable weighted-average exercise price.

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

General

As of February 13, 2012, our General Partner and its affiliates owned 19,544,089 common units representing an aggregate 44.5% limited partner interest in us. In addition, as of February 13, 2012, our General Partner owned approximately a 1.74% general partner interest in us and all of the incentive distribution rights. We and our General Partner and its affiliates are also parties to various contractual arrangements. The terms of these arrangements are not the result of arm's length negotiations.

Distributions and Payments to Our General Partner and its Affiliates

We make cash distributions of approximately 98.26% to our unitholders pro rata, including our General Partner and its affiliates, as the holders of an aggregate 19,544,089 common units, and 1.74% to our General Partner. In addition, if distributions exceed the minimum quarterly distribution and other higher target distribution levels, our General Partner is entitled to increasing percentages of the distributions, up to 49.74% of the distributions above the highest target distribution level.

Assuming we have sufficient available cash to maintain the current level of quarterly distribution on all of our outstanding units for four quarters, our General Partner and its affiliates would receive an annual distribution of approximately $11.2 million on its general partner interest and incentive distribution rights and $38.3 million on their common limited partner units. For 2011, the General Partner and its affiliates were paid $44.4 million in cash.

During 2011, the General Partner also participated in the issuance of Class C units. In addition to the cash distributions noted previously, the General Partner also participated in paid-in-kind distributions associated with their ownership of Class C units. See Part II, Item 8, "Financial Statements and Supplementary Data — Notes to Financial Statements" — Note 17 — "Partners' Capital and Distributions." The General Partner received 43,747 additional Class C units during 2011 associated with quarterly distributions.

Omnibus Agreement

We have entered into an Omnibus Agreement with Crestwood Holdings and our General Partner that addresses the following matters:

- restrictions on Crestwood Holdings' ability to engage in certain midstream business activities or own certain related assets in the Hood, Somervell, Johnson, Tarrant, Hill, Parker, Bosque and Erath Counties in Texas ("Crestwood Holdings Counties");
- Crestwood Holdings' obligation to indemnify us for certain liabilities and our obligation to indemnify Crestwood for certain liabilities;
- our obligation to reimburse Crestwood Holdings for all expenses incurred by Crestwood Holdings (or payments made on our behalf) in conjunction with Crestwood Holdings' provision of general and administrative services to us, including salary and benefits of Crestwood Holdings personnel, our public company expenses, general and administrative expenses and salaries and benefits of our executive management who are Crestwood Holdings' employees;

- our obligation to reimburse Crestwood Holdings for all insurance coverage expenses it incurs or payments it makes with respect to our assets; and
- our obligation to reimburse Crestwood Holdings for all expenses incurred by Crestwood Holdings (or payments made on our behalf) in conjunction with Crestwood Holdings' provision of services necessary to operate, manage and maintain our assets.

Any or all of the provisions of the Omnibus Agreement are terminable by Crestwood Holdings at its option if our General Partner is removed without cause and units held by our General Partner and its affiliates are not voted in favor of that removal. The Omnibus Agreement terminates on the earlier of August 10, 2017 or at such times as Crestwood Holdings ceases to own or control a majority of the issued and outstanding voting securities of our General Partner.

Competition

Under the Omnibus Agreement, Crestwood Holdings has agreed that, subject to specified exceptions, it will not engage in the restricted businesses in the Crestwood Holdings Counties. As used in that agreement, "restricted businesses" include the gathering, processing, treating, compression, fractionating, transportation and sales or storage of natural gas, or the transportation or storage of NGL's. Although the exceptions referred to above include Crestwood Holdings' right to acquire assets or businesses, that include restricted businesses, Crestwood Holdings has agreed to offer us the right to acquire any such midstream business assets for their construction costs, in the case of constructed assets, or fair market value, in the case of acquired assets. Furthermore, that offer would be required to be made not more than 120 days after Crestwood Holdings' construction or acquisition of those assets or construction and the commencement of service.

Except as described in the immediately preceding paragraph, neither Crestwood Holdings nor any of its affiliates will be restricted, under either the Partnership Agreement or the Omnibus Agreement, from competing with us. Subject to the preceding paragraph, Crestwood Holdings and any of its affiliates may acquire, construct or dispose of additional midstream business assets or other assets in the future without any obligation to offer us the opportunity to purchase or construct those assets.

Indemnification

Under the Omnibus Agreement, we have agreed to indemnify Quicksilver Resources Inc. for all losses attributable to the post-closing operations of the gathering and processing business contributed to us at the closing of our initial public offering unless in any such case indemnification would not be permitted under our Partnership Agreement.

Reimbursement of Compensation and Benefits

During 2011 reimbursements to Crestwood Holdings pursuant to the Omnibus Agreement consisted of payments of $13.6 million and $3.2 million in compensation and benefits for Crestwood Holdings personnel and executive management, respectively.

Reimbursement of Operating and General and Administrative Expenses

Under the Omnibus Agreement, we will reimburse Crestwood Holdings for the payment of certain operating expenses and for the provision of various general and administrative services for our benefit with respect to our assets. The Omnibus Agreement further provides that we will reimburse Crestwood Holdings for all expenses it incurs or payments it makes with respect to our assets. Pursuant to these arrangements, Crestwood Holdings performs centralized corporate functions for us, such as legal, accounting, treasury, cash management, insurance administration and claims processing, risk management, health, safety and environmental, information technology, human resources, credit, payroll, internal audit, taxes and engineering. Generally, these allocations are based on the amount of time individuals performing these functions devote to our business and affairs relative to the amount of time that we believe they devote to Crestwood Holdings' business and affairs.

Reimbursement for Operations, Services and Expenses

Under the Omnibus Agreement, we will reimburse Crestwood Holdings for all expenses incurred on our behalf in conjunction with services provided by Crestwood Holdings that are necessary to operate, manage and maintain our assets. Such services include, but are not limited to, (i) salaries and other wages of Crestwood Holdings personnel performing such services ("Operations Personnel"), (ii) bonus amounts paid to Operations Personnel, (iii) paid time off, benefits granted to Operations Personnel, (iv) employee benefits to Operations Personnel, (v) grants of cash for settled phantom units, if any, (vi) severance payments, if any, (vii) workers compensation insurance, and (viii) any of the employee costs or benefits relating to Operations Personnel for which Crestwood Holdings incurs costs.

Contracts with Affiliates

Agreements with Related Parties

Detailed description of our agreements with related parties, including Quicksilver Resources Inc., can be found in Part II, Item 8, "Financial Statements and Supplementary Data — Notes to Financial Statements" — Note 16 — "Transactions with Related Parties " of this report, which is incorporated herein by reference.

Policies and Procedures for Review and Approval of Transactions with Related Parties

The Board has adopted a written policy covering transactions with related parties pursuant to which it has delegated to the conflicts committee the responsibility for reviewing and, if appropriate, approving or ratifying such transactions. The policy covers transactions to which we or any of our subsidiaries is a party and in which any director or executive officer of our General Partner or any person that beneficially owns more than 5% of our common units, any immediate family member of such director, officer or owner, or any related entity of such related party, had, has or will have a direct or indirect interest, other than a transaction involving (a) compensation by us or (b) less than $120,000. The policy instructs directors and executive officers to bring any possible related-party transaction to the attention of our General Partner's General Counsel or Compliance Officer, who, unless he or she determines that the transaction is not a related-party transaction, will notify the chairman of the conflicts committee. The conflicts committee reviews each related-party transaction of which it becomes aware and may approve or ratify a related-party transaction if the conflicts committee determines that the transaction is in the best interest of us and our unitholders. In making this determination, the conflicts committee considers (i) whether the terms of the transaction are more or less favorable to us than those that could be expected to be obtained from an unrelated third party on an arm's length basis (ii) any provisions in our financing arrangements relating to transactions with related parties or affiliates; and (iii) any other matters the committee deems relevant and appropriate. The conflicts committee reports periodically to the Board on the nature of the transactions with related parties that have been presented to the conflicts committee and the determinations that the conflicts committee has made with respect to those transactions.

Director Independence

The Board has adopted categorical independence standards consistent with the current listing standards of the NYSE to assist the Board in determining which of its members is independent. A copy of the categorical independence standards appears in the Corporate Overview section under Corporate Governance of our website www.crestwoodlp.com. The Board has determined that each of Messrs. Bledsoe, Gettig and Somerhalder satisfies our General Partner's categorical independence standards and further determined that each of them is independent within the meaning of NYSE listing standards. The NYSE does not require a listed limited partnership like us to have a majority of independent directors, a compensation committee or a nominating and governance committee. Accordingly, each director of Crestwood Gas Services GP LLC may participate in consideration of compensation, nomination and governance matters.

Presiding Non-Management Director and Executive Sessions

Our General Partner's non-management directors meet in executive session without management either before or after regularly scheduled board meetings. In May 2011, the Board elected John W. Somerhalder II as Presiding Non-Management Director, in accordance with the NYSE rules. In his capacity as Presiding Non-Management Director, Mr. Somerhalder's primary responsibility is to preside over regularly scheduled executive sessions of the non-management directors of our General Partner.

Communication with the Board

Any interested party who wishes to communicate directly with the Board or any of its members may do so by writing to: Board of Directors (or one or more named individuals), Crestwood Midstream Partners LP, 717 Texas Avenue, Suite 3150, Houston, Texas 77002. Additionally, any interested party can contact the non-management directors at (832) 519-2200.

Item 14. Principal Accountant Fees and Services

Audit Fees

The following sets forth fees billed by Deloitte & Touche LLP for the audit of our annual financial statements and other services rendered for the years ended December 31, 2011 and 2010:

	Fees Billed for the Year Ended December 31, 2011	2010
Audit fees (1)	$ 523,823	$272,467
Audit-related fees (2)	—	—
Tax fees (3)	—	—
All other fees (4)	516,456	—
Total	$1,040,279	$272,467

(1) Includes fees for audits of annual financial statements and reviews of the related quarterly financial statements.
(2) There were no audit-related fees for 2011 or 2010.
(3) There were no tax fees billed for 2011 or 2010.
(4) Includes fee related to comfort letters, due diligence and other expense not directly related to audits of annual or quarterly financial statements.

Pre-approval Policy

Pursuant to its charter, the audit committee is responsible for the oversight of our accounting, reporting and financial practices. The audit committee has the responsibility to select, appoint, engage, oversee, retain, evaluate and terminate our external auditors and to pre-approve all audit and non-audit services. The audit committee has delegated to its chairman the responsibility to pre-approve all audit and non-audit services, provided that these decisions are presented to the full audit committee at its next regularly scheduled meeting.

PART IV

Item 15. Exhibits and Financial Statement Schedules

The following documents are filed as part of this report:

1. Financial Statements:

The following financial statements of ours and the report of our Independent Auditors thereon are included on pages 60 through 91of this Form 10-K.

Report of Independent Registered Public Accounting Firm

Consolidated Statements of Income for the Years Ended December 31, 2011, 2010 and 2009

Consolidated Balance Sheets as of December 31, 2011 and 2010

Consolidated Statements of Cash Flows for the Years Ended December 31, 2011, 2010 and 2009

Consolidated Statements of Changes in Partners' Capital for the Years Ended December 31, 2011, 2010 and 2009

Notes to Consolidated Financial Statements for the Years Ended December 31, 2011, 2010 and 2009

2. Financial Statement Schedules:

All schedules are omitted because the required information is inapplicable or the information is presented in the financial statements or the notes thereto.

3. Exhibits:

See Exhibit Index incorporated here into.

SIGNATURES

Pursuant to the requirements of Section 13 of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

CRESTWOOD MIDSTREAM PARTNERS LP
By: CRESTWOOD GAS SERVICES GP LLC, its general partner

By: /s/ Robert G. Phillips

Robert G. Phillips
President and Chief Executive Officer

Dated:February 29, 2012

Pursuant to the requirements of the Securities Exchange Act of 1934, the following persons on behalf of the registrant and in the capacities and on the dates indicated have signed this report below.

SIGNATURE	TITLE	DATE
/s/ Robert G. Phillips Robert G. Phillips	President, Chief Executive Officer and Chairman of the Board *(Principal Executive Officer)*	February 29, 2012
/s/ William G. Manias William G. Manias	Senior Vice President — Chief Financial Officer *(Principal Financial Officer)*	February 29, 2012
/s/ Steven A. Stophel Steven A. Stophel	Interim Chief Accounting Officer *(Principal Accounting Officer)*	February 29, 2012
/s/ Alvin Bledsoe Alvin Bledsoe	Director	February 29, 2012
/s/ Philip W. Cook Philip W. Cook	Director	February 29, 2012
/s/ Timothy H. Day Timothy H. Day	Director	February 29, 2012
/s/ Michael G. France Michael G. France	Director	February 29, 2012
/s/ Philip D. Gettig Philip D. Gettig	Director	February 29, 2012
/s/ Joel C. Lambert Joel C. Lambert	Director	February 29, 2012
/s/ J. Hardy Murchison J. Hardy Murchison	Director	February 29, 2012
/s/ John W. Somerhalder II John W. Somerhalder II	Director	February 29, 2012

EXHIBIT INDEX

Exhibit No.	Description
2.1	Purchase and Sale Agreement, dated December 10, 2009, among Cowtown Pipeline L.P., Quicksilver Gas Services LP and Cowtown Pipeline Partners L.P. (filed as Exhibit 10.1 to the Company's Form 8-K filed December 10, 2009 and included herein by reference).
2.2	Letter Agreement, dated December 29, 2009, among Cowtown Pipeline L.P., Quicksilver Gas Services LP and Cowtown Pipeline Partners L.P. (filed as Exhibit 2.2 to the Company's Form 10-K for the year ended December 31, 2009, filed on March 15, 2010 and included herein by reference).
2.3	Purchase and Sale Agreement by and between Frontier Gas Services, LLC and Crestwood Midstream Partners LP, dated as of February 18, 2011 (included as Exhibit 2.1 to the Company's Form 8-K filed February 22, 2011 and included herein by reference).
3.1	Certificate of Limited Partnership of Quicksilver Gas Services LP (filed as Exhibit 3.1 to the Company's Form S-1, File No. 33-140599, filed February 12, 2007 and included herein by reference).
3.2	Certificate of Amendment to the Certificate of Limited Partnership of Quicksilver Gas Services LP (filed as Exhibit 3.1 to the Company's Form 8-K, filed October 7, 2010 and included herein by reference)
3.3	Second Amended and Restated Agreement of Limited Partnership of Quicksilver Gas Services LP, dated February 19, 2008 (filed as Exhibit 3.1 to the Company's Form 8-K filed February 22, 2008 and included herein by reference).
3.4	First Amendment to the Second Amended and Restated Agreement of Limited Partnership of Quicksilver Gas Services LP (filed as Exhibit 3.2 to the Company's Form 10-Q for the Quarter ended September 30, 2010, filed on November 8, 2010 and included herein by reference)
3.5	Second Amendment to Second Amended and Restated Agreement of Limited Partnership of Crestwood Midstream Partners LP dated as of April 1, 2011 (included as Exhibit 3.1 to the Company's Form 8-K filed April 1, 2011, and included herein by reference).
3.6	Certificate of Formation of Quicksilver Gas Services GP LLC (filed as Exhibit 3.3 to the Company's Form S-1, File No. 333-140599, filed February 12, 2007 and included herein by reference).
3.7	Certificate of Amendment to the Certificate of Formation of Quicksilver Gas Services GP LLC (filed as Exhibit 3.3 to the Company's Form 10-Q for the Quarter ended September 30, 2010, filed on November 8, 2010 and included herein by reference).
3.8	First Amended and Restated Limited Liability Company Agreement of Quicksilver Gas Services GP LLC, dated July 24, 2007 (filed as Exhibit 3.4 to the Company's Form S-1/A, File No. 333-140599, filed July 25, 2007 and included herein by reference).
3.9	First Amendment to the First Amended and Restated Limited Liability Company Agreement of Quicksilver Gas Services GP LLC, dated July 24, 2007 (filed as Exhibit 3.4 to the Company's Form 10-Q for the quarter ended September 30, 2010, filed on November 8, 2010 and included herein by reference)
4.1	Form of Common Unit Certificate (filed as Exhibit 4.1 to the Company's Form S-3/A, File No. 333-171735, filed April 8, 2011 and included herein by reference).
4.2	Indenture, dated April 1, 2011, among Crestwood Midstream Partners LP and Crestwood Midstream Finance Corporation, the Guarantors named therein and The Bank of New York Mellon Trust Company, N.A., as trustee (included as Exhibit 4.1 to the Company's Form 8-K filed April 1, 2011, and included herein by reference).

*4.3	Supplemental Indenture No. 1 dated November 29, 2011 to Indenture dated April 1, 2011, among Crestwood Midstream Partners LP and Crestwood Midstream Finance Corporation, Crestwood Sabine Pipeline LLC, Sabine Treating, LLC, the other Guarantors named therein and The Bank of New York Mellon Trust Company, N.A., as trustee.
*4.4	Supplemental Indenture No. 2 dated January 6, 2012 to Indenture dated April 1, 2011, among Crestwood Midstream Partners LP and Crestwood Midstream Finance Corporation, Crestwood Appalachia Pipeline LLC, the other Guarantors named therein and The Bank of New York Mellon Trust Company, N.A., as trustee.
4.5	Form of Note representing all 7.75% Senior Notes due 2019 (included in Exhibit 4.2).
4.6	Registration Rights Agreement, dated April 1, 2011, among Crestwood Midstream Partners LP and Crestwood Midstream Finance Corporation, the Guarantors named therein and UBS Securities LLC, BNP Paribas Securities Corp., RBC Capital Markets, LLC and RBS Securities Inc., as the initial purchasers (included as Exhibit 4.3 to the Company's Form 8-K filed April 1, 2011, and included herein by reference).
4.7	Class C Unit Registration Rights Agreement, dated April 1, 2011, by and between Crestwood Midstream Partners LP and the purchasers named therein (included as Exhibit 4.4 to the Company's Form 8-K filed April 1, 2011, and included herein by reference).
10.1	Assignment and Conveyance, effective April 30, 2007, between Cowtown Pipeline Partners L.P. and Cowtown Pipeline L.P. (filed as Exhibit 10.13 to the Company's Form S-1/A, File No. 333-140599, filed July 30, 2007 and included herein by reference).
10.2(a)	Form of Assignment, effective April 30, 2007, between Cowtown Pipeline Partners L.P. and Cowtown Pipeline L.P. (filed as Exhibit 10.14(a) to the Company's Form S-1/A, File No. 333-140599, filed July 30, 2007 and included herein by reference).
10.2(b)	Schedule of Assignments, effective April 30, 2007, between Cowtown Pipeline Partners L.P. and Cowtown Pipeline L.P. (filed as Exhibit 10.14(b) to the Company's Form S-1/A, File No. 333-140599, filed July 30, 2007 and included herein by reference).
#10.3	Credit Agreement, dated as of October 1, 2010, among Crestwood Midstream Partners LP (f/k/a Quicksilver Gas Services LP), BNP Paribas as administrative agent and collateral agent, Banc of America Securities LLC, BNP Paribas Securities Corp. and RBC Capital Markets Corporation, as joint lead arrangers and joint bookrunners, Bank of America, N.A. and Royal Bank of Canada, as syndication agents, and UBS Securities and The Royal Bank of Scotland PLC as co-documentation agents.
10.4	Subordinated Promissory Note, dated as of August 10, 2007, made by Quicksilver Gas Services LP payable to the order of Quicksilver Resources Inc. (filed as Exhibit 10.2 to the Company's Form 8-K filed August 16, 2007 and included herein by reference).
10.5	Omnibus Agreement, dated August 10, 2007, among Quicksilver Gas Services LP, Quicksilver Gas Services GP LLC and Quicksilver Resources Inc. (filed as Exhibit 10.4 to the Company's Form 8-K filed August 16, 2007 and included herein by reference).
10.6	Omnibus Agreement, dated October 8, 2010, by and among Crestwood Midstream Partners LP, Crestwood Gas Services GP LLC and Crestwood Holdings Partners, LLC (filed as Exhibit 3.1 to the Company's Form 8-K filed October 13, 2010 and included herein by reference).
10.7	Extension Agreement, dated December 3, 2008, between Quicksilver Gas Services LP and Quicksilver Resources Inc. (filed as Exhibit 10.8 to the Company's Form 10-K for the year ended December 31, 2009, filed on March 15, 2010).

10.8	Option, Right of First Refusal, and Waiver in Amendment to Omnibus Agreement and Gas Gathering and Processing Agreement, dated as of June 9, 2009, among Quicksilver Resources Inc., Quicksilver Gas Services LP, Quicksilver Gas Services GP LLC, Cowtown Pipeline Partners L.P. and Cowtown Gas Processing Partners L.P. (filed as Exhibit 10.1 to the Company's Form 8-K filed June 11, 2009 and included herein by reference).
10.9	Waiver, dated November 19, 2009, by Quicksilver Gas Services GP LLC (filed as Exhibit 10.1 to the Company's Form 8-K filed November 23, 2009 and included herein by reference).
10.10	Waiver, dated November 19, 2009, by Quicksilver Resources Inc. (filed as Exhibit 10.2 to the Company's Form 8-K filed November 23, 2009 and included herein by reference).
10.11	Contribution, Conveyance and Assumption Agreement, dated August 10, 2007, among Quicksilver Gas Services LP, Quicksilver Gas Services GP LLC, Cowtown Gas Processing L.P., Cowtown Pipeline L.P., Quicksilver Gas Services Holdings LLC, Quicksilver Gas Services Operating GP LLC, Quicksilver Gas Services Operating LLC and the private investors named therein (filed as Exhibit 10.3 to the Company's Form 8-K filed August 16, 2007 and included herein by reference).
10.12	Sixth Amended and Restated Gas Gathering and Processing Agreement, dated September 1, 2008, among Quicksilver Resources Inc., Cowtown Pipeline Partners L.P. and Cowtown Gas Processing Partners L.P. (filed as Exhibit 10.1 to the Company's Form 10-Q filed November 6, 2008 and included herein by reference).
10.13	Second Amendment to the Sixth Amended and Restated Gas Gathering and Processing Agreement, dated as of October 1, 2010, by and among Quicksilver Resources Inc., Cowtown Pipeline Partners L.P. and Cowtown Gas Processing Partners L.P.
10.14	Gas Gathering Agreement, effective December 1, 2009, between Cowtown Pipeline L.P. and Quicksilver Resources Inc. (filed as Exhibit 10.1 to the Company's Form 8-K filed on January 8, 2010 and included herein by reference).
10.15	Amendment to Gas Gathering Agreement, dated as of October 1, 2010, by and between Quicksilver Resources Inc. and Cowtown Pipeline Partners L.P.
10.16	Addendum and Amendment to Gas Gathering and Processing Agreement Mash Unit Lateral, effective as of January 1, 2009, among Quicksilver Resources Inc., Cowtown Pipeline Partners L.P. and Cowtown Gas Processing Partners L.P. (filed as Exhibit 10.15 to the Company's Form 10-K for the year ended December 31, 2009, filed on March 15, 2010).
10.17	Joint Operating Agreement, dated October 1, 2010, but effective as of July 1, 2010, between Quicksilver Resources Inc., Quicksilver Gas Services LP and Quicksilver Gas Services GP LLC (filed as Exhibit 10.20 to the Company's Form 10-K for the year ended December 31, 2010, filed on February 25, 2011).
10.18	Class C Unit Purchase Agreement by and among Crestwood Midstream Partners LP and the purchases named therein, dated as of February 18, 2011 (included as Exhibit 10.1 to the Company's Form 8-K filed February 22, 2011 and included herein by reference).
+10.19	Letter Agreement dated September 7, 2010 between the Crestwood Midstream Partners LP and Mark G. Stockard (filed as Exhibit 10.22 to the Company's Form 10-K for the year ended December 31, 2010, filed on February 25, 2011).
*+10.20	Letter Agreement dated September 20, 2010, between Crestwood Midstream Partners LP and Kelly J. Jameson.
10.21	Joinder Agreement, dated as of April 1, 2011, by and among RBC Capital Markets Corporation, UBS Securities LLC and Bank of America, N.A., and Crestwood Midstream Partners LP and BNP Paribas, as Administrative Agent, Swingline Lender and Issuing Bank (included as Exhibit 10.1 to the Company's Form 8-K filed April 1, 2011, and included herein by reference).

10.22	Separation Agreement and Release, dated October 29, 2011, by and among Crestwood Midstream Partners, LP, Crestwood Gas Services GP. LLC, Crestwood Holdings Partners, LLC, Crestwood Midstream Partners II, LLC and Terry L. Morrison (incorporated by reference herein to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on November 1, 2011).
+10.23	Crestwood Midstream Partners LP Third Amended and Restated 2007 Equity Plan.
+10.24	Form of Phantom Unit Award Agreement for Directors (3-year).
+10.25	Form of Phantom Unit Award Agreement for Directors (1-year).
+10.26	Form of Phantom Unit Award Agreement for Non-Directors (Cash).
+10.27	Form of Phantom Unit Award Agreement for Non-Directors (Units).
*+10.28	Form of Phantom Unit Award Agreement for Non-Directors (Restricted Units)
+10.29	Form of Indemnification Agreement by and between Crestwood Midstream Partners LP and its officers and directors.
*21.1	List of Subsidiaries of Crestwood Midstream Partners LP.
*23.1	Consent of Deloitte & Touche LLP.
*31.1	Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*31.2	Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*32.1	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
**101.INS	XBRL Instance Document
**101.SCH	XBRL Taxonomy Extension Schema Linkbase Document
**101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document
**101.DEF	XBRL Taxonomy Extension Definition Linkbase Document
**101.LAB	XBRL Taxonomy Extension Labels Linkbase Document
**101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document

* Filed herewith
\+ Identifies management contracts and compensatory plans or arrangements.
\# Confidential treatment has been requested for certain portions which are omitted in the copy of the exhibit electronically filed with the SEC. The omitted information has been filed separately with the SEC pursuant to our application for confidential treatment.
** Furnished and not filed herewith

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Non-GAAP Reconciliation

Crestwood Midstream Partners LP

(Dollar amounts in thousands)

Year ended December 31	2008	2009	2010	2011
Net income from continuing operations	$28,472	$ 34,491	$ 34,872	$ 45,003
Loss from discontinued operations	(2,330)	(1,992)	–	–
Net income	26,142	32,499	34,872	45,003
Items impacting net income:				
Gain from exchange of property, plant and equipment	–	–	–	(1,106)
Non-cash compensation (accelerated vesting)	–	–	3,581	–
Transition related expenses	–	–	2,737	3,385
Non-cash interest expense (write-off of deferred financing costs)	–	–	1,558	2,500
Adjusted net income	$26,142	$ 32,499	$ 42,748	$ 49,782
Total revenues	$76,084	$ 95,881	$113,590	$205,820
Operations and maintenance expense	(19,395)	(21,968)	(25,702)	(36,303)
Product purchases	–	–	–	(38,787)
General and administrative expense	(6,407)	(9,676)	(17,657)	(24,153)
Other income	11	1	–	–
Gain from exchange of property, plant and equipment	–	–	–	1,106
EBITDA	50,293	64,238	70,231	107,683
Items impacting EBITDA	–	–	6,318	2,279
Adjusted EBITDA	50,293	64,238	76,549	109,962
Less:				
Depreciation, amortization and accretion expense	13,131	20,829	22,359	33,812
Interest expense	8,437	8,519	13,550	27,617
Income tax provision (benefit)	253	399	(550)	1,251
Items impacting EBITDA	–	–	6,318	2,279
Net income from continuing operations	$28,472	$ 34,491	$ 34,872	$ 45,003
Net income from continuing operations	$28,472	$ 34,491	$ 34,872	$ 45,003
Depreciation, amortization and accretion expense	13,131	20,829	22,359	33,812
Income tax provision (benefit)	253	399	(550)	1,251
Deferred financing fees, debt issuance costs and other	6,096	3,836	4,961	3,473
Non-cash equity compensation	1,017	1,705	5,522	916
Maintenance capital expenditures	(1,890)	(10,000)	(6,600)	(1,409)
Distributable cash flow	47,079	51,260	60,564	83,046
Add: Items impacting distributable cash flow	–	–	2,737	4,779
Adjusted distributable cash flow	$47,079	$ 51,260	$ 63,301	$ 87,825

Board of Directors

Robert G. Phillips
Chairman, President and CEO of Crestwood Gas Services GP LLC
Advisory Director of Triten Corporation

Alvin Bledsoe (1)
Retired Partner, Pricewaterhouse-Coopers
Director of SunCoke Energy, Inc.

Philip W. Cook
Executive Vice President, Chief Financial Officer, Quicksilver Resources Inc.

Timothy H. Day
Managing Director, First Reserve Corporation

Michael G. France
Managing Director, First Reserve Corporation

Philip D. Gettig (2)
Retired General Counsel, Union Pacific Fuels, Inc.

Joel C. Lambert
Associate General Counsel, First Reserve Corporation

J. Hardy Murchison
President, Encino Energy, LLC

John W. Somerhalder II (3)
Chairman, President and Chief Executive Officer AGL Resources Inc.

(1) Chair of Audit Committee, member of Conflicts Committee

(2) Chair of Conflicts Committee, member of Audit Committee

(3) Member of Audit Committee and Conflicts Committee

Executive Officers

William G. Manias
Senior Vice President and Chief Financial Officer

Joel D. Moxley
Senior Vice President and Chief Operating Officer

Kelly J. Jameson
Senior Vice President General Counsel and Corporate Secretary

Investor Information

Exchange Information
Our common units are traded on the NYSE under the symbol "CMLP".

Additional Information
For more information, please visit our website at www.crestwoodlp.com. Through our website, you may elect to receive news, SEC filings and other information.

Transfer Agent
For information regarding change of address or other matters concerning your units, please contact our transfer agent Computershare (formerly known as Mellon Investor Services LLC), directly at:
Computershare
480 Washington Blvd.
Jersey City, New Jersey
07310-1900
Phone: (888) 581-9370
www.bnymellon.com/shareowner/equityacess

Principal Executive Offices
Crestwood Midstream Partners LP
717 Texas Avenue, Suite 3150
Houston, TX 77002
Phone: (832) 519-2200
Fax: (832) 519-2250

Crestwood Midstream Partners LP is managed by its General Partner, Crestwood Gas Services GP LLC, which is owned and managed by Crestwood Holdings Partners, LLC (Crestwood Holdings), a partnership formed in 2010 between First Reserve and the Crestwood management team.

Crestwood®
MIDSTREAM PARTNERS LP

CRESTWOOD MIDSTREAM PARTNERS LP 2011 ANNUAL REPORT