PAA NATURAL GAS STORAGE LP
Form 10-K
February 29, 2012

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

(Mark One)

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

For the fiscal year ended December 31, 2011

or

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

Commission file number 1-34722

PAA Natural Gas Storage, L.P.

(Exact name of registrant as specified in its charter)

Delaware	**27-1679071**

(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
333 Clay Street, Suite 1500, Houston, Texas	**77002**
(Address of principal executive offices)	(Zip Code)

(713) 646-4100

(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 Representing 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 x

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

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

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	x
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 x

The aggregate market value of the Common Units held by non-affiliates of the registrant (treating all executive officers and directors of the registrant and holders of 10% or more of the Common Units outstanding, for this purpose, as if they may be affiliates of the registrant) was approximately $695 million on June 30, 2011, based on a closing price of $22.67 per Common Unit as reported on the New York Stock Exchange on such date.

At February 22, 2012, there were outstanding 59,193,825 Common Units.

DOCUMENTS INCORPORATED BY REFERENCE

NONE

Table of Contents

PAA NATURAL GAS STORAGE, L.P. AND SUBSIDIARIES

FORM 10-K 2011 ANNUAL REPORT

Table of Contents

Table of Contents

FORWARD-LOOKING STATEMENTS

All statements included in this report, other than statements of historical fact, are forward-looking statements, including but not limited to statements incorporating the words anticipate, believe, estimate, expect, plan, intend and forecast, as well as similar expressions and st regarding our business strategy, plans and objectives for future operations. The absence of these words, however, does not mean that the statements are not forward-looking. These statements reflect our current views with respect to future events, based on what we believe to be reasonable assumptions. Certain factors could cause actual results to differ materially from the results anticipated in the forward-looking statements. The most important of these factors include, but are not limited to:

significantly reduced volatility and/or lower spreads in natural gas markets for an extended period of time;

factors affecting demand for natural gas storage services and the rates we are able to charge for such services, including the balance between the supply of and demand for natural gas;

our ability to maintain or replace expiring storage contracts, or enter into new storage contracts, in either case at attractive rates and on otherwise favorable terms;

factors affecting our ability to realize revenues from hub services and merchant storage transactions involving uncontracted or unutilized capacity at our facilities;

the effects of competition;

the impact of operational, geologic and commercial factors that could result in an inability on our part to satisfy our contractual commitments and obligations, including the impact of equipment performance, cavern operating pressures, cavern temperature variances, salt creep and subsurface conditions or events;

risks related to the ownership, development and operation of natural gas storage facilities;

failure to implement or execute planned internal growth projects on a timely basis and within targeted cost projections;

the effectiveness of our risk management activities;

operational, geologic or other factors that affect the timing or amount of crude oil and other liquid hydrocarbons that we are able to produce in conjunction with the operation of our Bluewater facility;

market or other factors that affect the prices we are able to realize for crude oil and other liquid hydrocarbons produced in conjunction with the operation of our Bluewater facility;

interruptions in service and fluctuations in tariffs or volumes on third-party pipelines;

general economic, market or business conditions and the amplification of other risks caused by volatile financial markets, capital constraints and pervasive liquidity concerns;

the successful integration and future performance of acquired assets or businesses;

our ability to obtain debt or equity financing on satisfactory terms to fund additional acquisitions, expansion projects, working capital requirements and the repayment or refinancing of indebtedness;

the impact of current and future laws, rulings, governmental regulations, accounting standards and statements and related interpretations;

our ability to obtain and/or maintain all permits, approvals and authorizations that are necessary to conduct our business and execute our capital projects;

shortages or cost increases of supplies, materials or labor;

weather interference with business operations or project construction;

our ability to receive open credit from our suppliers and trade counterparties;

Table of Contents

continued creditworthiness of, and performance by, our counterparties, including financial institutions and trading companies with which we do business;

the availability of, and our ability to consummate, acquisition or combination opportunities;

the operations or financial performance of assets or businesses that we acquire;

environmental liabilities or events that are not covered by an indemnity, insurance or existing reserves;

increased costs or unavailability of insurance;

fluctuations in the debt and equity markets, including the price of our units at the time of vesting under our long-term incentive plan; and

other factors and uncertainties inherent in the ownership, development and operation of natural gas storage facilities.

Other factors described herein, as well as factors that are unknown or unpredictable, could also have a material adverse effect on future results. See Item 1A. Risks Factors. Except as required by applicable securities laws, we do not intend to update these forward-looking statements and information.

Table of Contents

PART I

Items 1 and 2. ***Business and Properties***

General

PAA Natural Gas Storage, L.P. is a Delaware limited partnership formed by Plains All American Pipeline, L.P. (PAA) on January 15, 2010. Our operations are conducted directly and indirectly through our primary operating subsidiaries. As used in this Form 10-K and unless the context indicates otherwise, the terms Partnership, PNG, we, us, our, ours and similar terms refer to PAA Natural Gas Storage, L.P. and its subsic

Our business consists of the acquisition, development, ownership, operation and commercial management of natural gas storage facilities. As of December 31, 2011, we owned and operated three natural gas storage facilities located in Louisiana, Mississippi and Michigan. We also lease storage capacity and pipeline transportation capacity from third parties from time to time in order to increase our operational flexibility and enhance the services we offer our customers.

We provide natural gas storage services to a broad mix of customers, including local gas distribution companies, or LDCs, electric utilities, pipelines, direct industrial users, electric power generators, marketers, producers, LNG importers and affiliates of such entities. Our storage rates are regulated under Federal Energy Regulatory Commission, or FERC, rate-making policies, which currently permit our facilities to charge market-based rates for our services.

Organizational History

We were formed as a limited partnership to own, operate and grow the natural gas storage business of PAA, in which it acquired its initial interest in 2005. Our 2% general partner interest is held by PNGS GP LLC, a Delaware limited liability company, whose sole member is PAA. References to our general partner, as the context requires, include only PNGS GP LLC.

Partnership Structure and Management

At December 31, 2011, PAA owned an aggregate direct and indirect 64% ownership interest in us comprised of the general partner s 2% interest, 28.3 million common units, 11.9 million Series A subordinated units and 13.5 million Series B subordinated units, as well as incentive distribution rights. The Series B subordinated units are not entitled to participate in our quarterly distributions unless and until they convert into Series A subordinated units or common units. The Series B subordinated units are, however, entitled to vote on matters submitted to a vote to our unitholders.

Table of Contents

The diagram below illustrates the structure of PAA Natural Gas Storage, L.P. at February 22, 2012.

(1) Incentive Distribution Rights (IDRs). See Item 5. Market for Registrant s Common Units, Related Unitholder Matters and Issuer Purchases of Equity Securities for discussion of our general partner s IDRs.

PNGS GP LLC, our general partner, has sole responsibility for conducting our business and for managing our operations. We have entered into an omnibus agreement with PAA and certain of its affiliates, which governs certain aspects of our relationship with them, including the provision by PAA s general partner to us of certain general and administrative services and employees, our agreement to reimburse PAA s general partner for the cost of such services and employees, certain indemnification obligations, the use by us of the name PAA and related marks, and other matters. See Item 10. Directors and Executive Officers of Our General Partner and Corporate Governance and Item 13. Certain Relationships and Related Transactions, and Director Independence Related Party Transactions Omnibus Agreement.

As is common with publicly traded partnerships and in order to maximize operational flexibility, we conduct our operations through our subsidiaries.

Our Business Strategy

Our principal business strategy is to capitalize on the anticipated long-term growth in demand for natural gas storage services in North America by owning and operating high-quality natural gas storage facilities and providing our current and future customers reliable, competitive and flexible natural gas storage and related services. In executing this strategy, we intend to expand the scope and scale of our business, grow our earnings and cash flow and increase the amount of cash distributions we make to our unitholders over time. Our plan for executing this strategy includes the following key components:

- *Optimizing our existing natural gas storage facilities.* Our primary commercial objective is to generate a significant portion of our revenues by committing a high percentage of our storage capacity under firm multi-year storage contracts. We also provide our customers with a variety of hub services that are designed to accommodate customer needs, maximize the utilization of our assets and optimize our earnings and cash flow. Commercially, and operationally, we routinely seek to optimize our profitability by executing various initiatives that increase our efficiency, reliability and flexibility.

- *Through our dedicated commercial marketing group, using a portion of our storage capacity in conjunction with our commercial marketing activities to enhance our margins.* Similar to the business model employed by PAA, and without altering our basic commercial strategy of committing a high percentage of our storage capacity under multi-year firm storage contracts with third parties, we have a dedicated commercial marketing group that captures market opportunities by utilizing a portion of our storage capacity for our own account and engaging in related commercial marketing activities.

- *Organically expanding our existing natural gas storage facilities.* Our existing assets enable us to expand our storage capacity on what we believe to be attractive economic terms. We currently have permitted expansion activities underway at each of our three facilities. Taking into account expansions that are currently under construction and permitted expansions not yet under construction, we have the potential to increase our capacity from approximately 76 billion cubic feet (Bcf) of working capacity at December 31, 2011 to an aggregate of approximately 149 Bcf of working capacity at these three facilities.

- *Pursuing strategic and accretive acquisition or development projects.* We continually evaluate opportunities to acquire or develop new natural gas storage facilities in our existing and new markets. In general, we seek acquisition or development opportunities that will be accretive (i.e. result in an increase in distributable cash flow on a per unit basis) and that will add natural gas storage assets or facilities that either complement our existing assets or strategically enhance our overall business by facilitating our entry into a desirable new market, diversifying our customer base or positioning us for future growth.

- *Leasing storage capacity and transportation services from third parties to enhance operational flexibility.* In order to supplement our owned storage capacity, increase our operating flexibility, enhance the services that we are capable of offering to our customers and optimize the commercial performance of our assets, we periodically lease storage and/or transportation capacity from third parties.

Our Financial Strategy

An important factor to successfully grow our business will be our ability to maintain a competitive cost of capital and sufficient access to the capital markets. These factors will be significantly influenced by our ability to sustain our current distribution as well as grow our distribution to unitholders, maintain a solid credit profile and ultimately achieve and maintain an investment-grade credit rating.

Targeted Credit Profile. We have targeted a general credit profile that has the following attributes:

- a long-term debt-to-total capitalization ratio of 40% or less;

- an average long-term debt-to-Adjusted EBITDA multiple of approximately 3.5x to 4.0x (Adjusted EBITDA is earnings before interest expense, taxes, depreciation, depletion and amortization, equity compensation plan expense, gains and losses from derivative activities and selected items that are generally unusual or non-recurring); and

- an average Adjusted EBITDA-to-interest coverage multiple of approximately 3.3x or better.

In order for us to maintain our targeted credit profile, we generally intend to fund approximately 60% of the capital required for future expansion projects (beyond the projects currently under development), as well as future acquisitions, through a combination of equity capital and cash flow in excess of distributions. From time to time, we may be outside the parameters of our targeted credit profile due to challenging market conditions, timing issues related to the initial funding of certain capital expenditures or acquisitions with debt or delays in realizing increases in Adjusted EBITDA, synergies or other benefits from expansion and/or acquisition projects.

When considered together with what we believe to be the relatively low-risk profile of our business, we believe this credit profile is consistent with an investment grade credit rating. In combination with our intent to maintain a high percentage of storage capacity under multi-year contracts, we believe this credit profile should provide flexibility during periods where storage markets become oversupplied and thus position us to take advantage of attractive acquisition opportunities.

Credit Rating. We have not applied for a credit rating from any credit rating agency, nor to our knowledge has any such credit rating been assigned. Additionally, we do not currently intend to apply for a credit rating until such time as we expect to access the public debt capital markets. If and when we seek a credit rating, our credit rating may be positively or negatively impacted by the leverage and credit rating of PAA. In addition, while we believe our targeted credit profile is consistent with an investment grade rating, we can provide no assurance in this regard. See Item 1A. Risk Factors Risks Related to Our Business The credit and risk profile of our general partner and its owner, PAA, could adversely affect our credit and risk profile, which could increase our borrowing costs or hinder our ability to raise capital.

Table of Contents

Our Competitive Strengths

We believe that the following competitive strengths will position us to successfully execute our principal business strategy:

Our natural gas storage assets are strategically located and operationally flexible. Our Pine Prairie, Southern Pines and Bluewater storage facilities are strategically positioned relative to several major market hubs and have extensive pipeline header systems that are interconnected directly or indirectly with multiple large-diameter interstate and intrastate pipelines. These facilities enable us to serve a variety of major producing regions and LNG importers or exporters, as well as the primary consumer and industrial markets in the Gulf Coast, Midwest, Northeast and Southeast. In the aggregate, our three facilities have peak injection and withdrawal capacity of 4.1 Bcf per day and 6.4 Bcf per day, respectively.

Our business generates relatively stable and predictable cash flow. Given the high percentage of our cash flow that is derived from fixed-capacity reservation fees under multi-year contracts with a diverse portfolio of customers, our baseline cash flow profile is relatively stable and predictable, which we believe significantly mitigates the risk to us of negative cash flow fluctuations caused by changing supply and demand conditions and other market factors. In addition, we do not take title to the natural gas that we store for our customers and, accordingly, are not exposed to commodity price fluctuations on the gas that is stored in our facilities by our customers.

Our dedicated commercial marketing group enhances our margins. Our dedicated commercial marketing group has the capability to capture short-term opportunities by utilizing a portion of our storage capacity for our own account and engaging in related commercial marketing activities. Through this group, we have a consistent presence in our markets that enhances our ability to properly price our long and short term storage offerings while positioning us to capitalize on volatility and inefficiency in natural gas markets. We conduct activities in our commercial marketing group within pre-defined risk parameters, and our general policy is (i) to purchase natural gas only in situations where we have a market for such gas, (ii) to utilize physical natural gas inventory and financial derivatives to manage and optimize seasonal and spread risks inherent in our business and to structure our transactions so that commodity price fluctuations will not have a material adverse impact on our cash flows and (iii) not to acquire or hold natural gas, futures contracts or other derivative products for the purpose of speculating on outright commodity price changes.

Our Gulf Coast storage facilities have the ability to be significantly expanded at competitive costs and with a relatively high degree of schedule certainty. Subject to market demand, project execution, sufficient pipeline capacity, available financing and receipt of future permits, we have the property rights and operational capacity to expand our Pine Prairie and Southern Pines facilities (Gulf Coast Facilities) significantly beyond their current size. In addition, because the existing infrastructure at both of these facilities has been specifically designed to facilitate future expansion, as we expand these facilities we expect to both reduce our overall capital costs per additional Bcf of storage capacity and shorten the length, and enhance the predictability of, our development cycle.

We have the evaluation, integration and engineering skill sets in-house that are necessary to successfully pursue acquisition and expansion opportunities. We possess the in-house capabilities and expertise necessary to develop, construct, own, acquire and operate both depleted reservoir and salt-cavern storage capacity. We and our predecessor have been involved in substantially all aspects of the natural gas storage business since 2005 and our operational and management teams have extensive energy industry and acquisition experience.

We have the financial flexibility to pursue acquisition and expansion opportunities. We believe our borrowing capacity and our ability to access private and public debt and equity capital should provide us with the financial flexibility necessary to execute our growth and expansion strategy. Additionally, PAA may elect, but is not obligated, to provide us with financial support in connection with acquisitions or expansion capital projects in certain circumstances.

Our general partner has an experienced management team with extensive knowledge of natural gas storage operations and markets and whose interests are aligned with those of our unitholders. Our general partner has an executive management team that has extensive experience managing, operating, building, acquiring and integrating energy assets, including natural gas storage assets and other midstream energy assets. Through their indirect and direct interests in us, our general partner and PAA, our general partner s executive and senior management team has a significant, vested interest in our continued success.

We believe these competitive strengths will aid our efforts to expand our presence in the natural gas storage sector.

Table of Contents

Our Relationship with PAA

We believe one of our strengths is our relationship with PAA, which is one of the largest publicly-traded master limited partnerships as measured by its equity market capitalization of approximately $11.4 billion as of December 31, 2011. Plains All American s common units trade on the New York Stock Exchange, or NYSE, under the ticker symbol PAA. In addition to its participation in the natural gas storage business through our partnership, PAA is engaged in the transportation, storage, terminalling and marketing of crude oil, refined products, natural gas liquids and liquefied petroleum gas and other natural gas-related petroleum products. PAA s assets include approximately 16,000 miles of pipelines, approximately 100 million barrels of storage capacity, and a significant fleet of trucks, trailers, tugs, barges and railcars. Through its transportation, storage and commercial activities, PAA physically handles in excess of 3 million barrels per day of petroleum products.

PAA and its predecessors have been active participants in the hydrocarbon storage industry since the early 1990s. PAA has a long history of successfully expanding its energy infrastructure businesses through a combination of organic growth projects and complementary acquisitions. Since its initial public offering in 1998, PAA has grown its asset base from approximately $600 million to over $15 billion and increased the annualized distribution on its limited partner units by over 125%, from $1.80 per unit as of PAA s initial public offering to $4.10 per unit for the distribution paid in February 2012.

Our partnership owns all of the natural gas storage business and assets formerly owned by PAA through a joint venture with Vulcan Energy and PAA has stated that it intends to utilize our partnership as the primary vehicle through which it will participate in the natural gas storage business. As the ultimate owner of our 2% general partner interest, all of our incentive distribution rights and an approximate 62% limited partner interest in us (including common units, Series A subordinated units and Series B subordinated units), PAA has a significant economic stake in us and is motivated to promote and support the successful execution of our growth plan and strategy.

We have also entered into an omnibus agreement with PAA and certain of its affiliates, pursuant to which PAA s general partner has agreed to provide us with certain general and administrative services and employees, and we have agreed to reimburse PAA s general partner for the costs of such services.

We believe PAA s significant presence in the energy sector, its successful track record of growth and its significant investment in, and sponsorship and support of, us enhances our ability to grow our business.

Recent Developments

Modification of Terms of Series B Subordinated Units

In February 2012, we modified the terms of the Partnership s 13.5 million Series B subordinated units, which modification was approved by PAA, the owner of all of the Series B subordinated units. The Partnership s Series B subordinated units do not participate in quarterly distributions. Instead, the Series B subordinated units convert into Series A subordinated units or common units in five distinct tranches upon the achievement of defined benchmarks tied to the amount of capacity in service at Pine Prairie and increases in our quarterly distributions. The modification increases the quarterly distribution benchmark for the first three of the five tranches, totaling 7.5 million Series B subordinated units in the aggregate, to an annualized level of $1.71 per unit. Previously, the quarterly distribution levels required to cause conversion for these three tranches were at annualized levels of $1.44, $1.53 and $1.63 per unit. The modification, which was made in recognition of the continued challenging market conditions facing the natural gas storage business, benefits our common unitholders by reducing the number of units on which distributions would otherwise be required to be paid in the case of distributions below the annualized level of $1.71.

Natural Gas Market Overview

North American natural gas storage facilities provide a staging and warehousing function for seasonal swings in demand relative to supply, as well as an essential reliability cushion against disruptions in natural gas supply, demand and transportation by allowing natural gas to be injected into, withdrawn from or warehoused in such storage facilities as dictated by market conditions. The long term demand for storage services in the United States is driven primarily by the long-term demand for natural gas and the overall lack of balance between the supply of and demand for natural gas on a seasonal, monthly, daily or other basis. In general and on a long term basis, to the extent the overall demand for natural gas increases and such growth includes higher demand from seasonal or weather-sensitive end-users (such as gas-fired power generators and residential and commercial consumers), demand for natural gas storage services should also grow. In addition, any factors that contribute to more frequent and severe imbalances between the supply of and demand for natural gas, whether caused by supply or demand fluctuations, should increase the need for and the value of storage services. On a short term basis, storage demand and values are also significantly influenced by operational imbalances, near term seasonal spreads, shorter term spreads and basis differentials.

Table of Contents

Natural Gas Demand. During the period from 2001 through 2011 domestic natural gas consumption has grown, albeit unevenly, driven primarily by growth in the seasonal and weather-sensitive electric power generation and commercial sectors, offset by declines in the residential and industrial sectors. The chart below, based on U.S. Energy Information Administration (EIA) data and forecasts, shows the overall growth in consumption (and the disposition of such growth) for the eleven year period ended October 2011. The chart also includes EIA forecasted data for December 2011.

Natural Gas Supply. For a number of years during the last decade, domestic natural gas production was relatively flat and failed to keep pace with domestic consumption. Over the past several years, however, domestic natural gas production has been growing rapidly. This trend reversal is primarily due to increases in production from developing shale resource plays. According to EIA data, domestic production of natural gas increased by 5.4% during the three year period from January 1, 2009 through December 31, 2011.[1] EIA forecasts also predict that shale gas production will increase 229% from 2009 to 2035.

Market Balance and Volatility. The seasonality of natural gas has remained strong during the last decade, with consumption during the peak winter months averaging approximately 40% more than consumption during the summer months, per EIA data. For the lower 48 states, from January 1, 2011 to December 31, 2011, U.S. consumption reached peak use of more than 115 Bcf on February 10, while the lowest daily consumption during this same period was approximately 48 Bcf on October 9, per EIA and other published daily data sources. On the other hand, daily U.S. production in the lower 48 during this same twelve month period ranged from 61 Bcf to 71 Bcf. Natural gas storage (and to a lesser extent imported natural gas from Canada) served as the shock absorber that balanced the market, serving as a source of supply to meet the consumption demands in excess of daily production capacity and a warehouse for gas production in excess of daily demand during low demand periods. This seasonal consumption pattern is a major driver of demand for gas storage and the price difference, or spread, between the summer and winter season provides a proxy for the fundamental value of storage.

During most of the past decade, this strong seasonal trend has produced seasonal spreads that have generally moved within a range of approximately $0.37-$4.75 per MMBtu, with the high end of that range occurring during the 2006-2007 timeframe. However, in 2011 the seasonal spreads (Oct-Jan) traded in a range of approximately $0.37-$0.62. In addition, lower short term spreads and basis differentials have reduced overall market volatility, which negatively impacts storage demand and value. While there are a variety of factors that have contributed to these softer market conditions, we believe the key drivers are (i) relatively flat natural gas consumption over the last year and projected flat consumption for the next several years, (ii) increased natural gas supplies due to production from shale resources, (iii) net increases in storage capacity, and (iv) lower basis differentials due to expansion of natural gas transportation infrastructure in the U.S. over the last five years.

1 Reported production per EIA was used through October 2011. For November and December 2011 reported production volume from November and December 2010 were used as proxies, respectively, for the final two months of 2011.

Table of Contents

Supply of Storage Capacity. An important factor in determining the value of storage is whether there is a surplus or shortfall of storage capacity relative to the overall demand for storage services in a given market area. In general, on a relative basis, storage values will be lower in markets that are oversupplied with storage than in markets where storage capacity is in short supply. The extent to which markets are oversupplied or undersupplied will fluctuate based on capacity additions and in response to significant variations in natural gas supply and demand.

According to EIA data and as indicated in the chart below, peak storage utilization as a percentage of peak storage capacity has ranged from 91% in 2005 to 99% in 2009 and decreased to 94% in 2011, in part due to a 5.5% increase in peak capacity relative to 2009 levels. Despite the increase in storage capacity, storage inventories, as reported by the EIA, reached a record peak level of 3.852 Tcf in November of 2011.

	Non Coincident Peak Capacity (TCF)	Max Inventory in Storage (TCF)	Peak Utilization
2005	3.600	3.282	91%
2006	3.609	3.461	96%
2007	3.703	3.545	96%
2008	3.789	3.488	92%
2009	3.889	3.837	99%
2010	4.049	3.840	95%
2011	4.103	3.852	94%

While it is difficult to predict when, and how much, new capacity will be added to the market in the next few years, we believe that certain of the supply and demand factors contributing to the current softness in the storage market (i.e., robust supply levels, low levels of natural gas demand growth and reduced price volatility) are cyclical and self correcting over time, and that the long term outlook for storage utilization and demand is positive.

Our Assets

As of December 31, 2011 we owned a 100% interest in three natural gas storage facilities. Our Pine Prairie and Southern Pines facilities are recently constructed, high-deliverability salt-cavern natural gas storage complexes located in Evangeline Parish, Louisiana and Greene County, Mississippi, respectively. Given the relative proximity of these two facilities to each other and the extent of direct and indirect connecting pipelines, we use a combination of interruptible storage services and third party transportation services to coordinate movements between and optimize the performance of these two Gulf Coast facilities. Our third facility is our Bluewater facility, a depleted reservoir natural gas storage complex located approximately 50 miles from Detroit in St. Clair County, Michigan. The following table contains certain information regarding our salt-cavern and depleted reservoir storage facilities as of December 31, 2011 (working gas capacity figures in the table below are based on assumed base gas levels, which may vary by facility based on commercial activities and other factors):

Table of Contents

Facility Type (Names)	Working Gas Capacity (Bcf)	Peak Injection Rate (Bcf/d)	Peak Withdrawal Rate (Bcf/d)	Compression (Horsepower)
Salt-caverns (Pine Prairie and Southern Pines)				
Total Existing	50	3.6	5.6	119,000
Total Permitted	120	3.6	5.6	146,500
Depleted Reservoirs (Bluewater)				
Total Existing	26	0.5	0.8	13,350
Total Permitted	29	0.5	0.8	13,350
Grand Total Existing (all facilities)	76	4.1	6.4	132,350
Grand Total Permitted (all facilities)	149	4.1	6.4	159,850

Salt Cavern Storage Facilities. We own two FERC regulated, high deliverability salt cavern natural gas storage facilities located on the Gulf Coast. Our Pine Prairie facility is located in Evangeline, Rapides and Acadian Parishes, Louisiana and is permitted for up to 80 Bcf of working gas capacity, which includes 32 Bcf of incremental capacity that was recently approved by the FERC subject to the requirement that Pine Prairie conduct an open season in accordance with applicable FERC policy. Our Southern Pines facility is located in Greene County Mississippi and is permitted for up to 40 Bcf of working gas capacity. These two facilities had an aggregate working gas capacity as of December 31, 2011 of approximately 50 Bcf. During 2012, we anticipate placing an additional 16 Bcf of working gas capacity in service at these facilities, which will include a fifth cavern at Pine Prairie that is scheduled to be placed into service in the second quarter of 2012, a fourth cavern at Southern Pines that is scheduled to be placed into service in the third quarter of 2012 and additional capacity at both facilities from incremental leaching activities.

Both of these facilities are strategically-located and have a diverse group of customers, including utilities, pipelines, producers, power generators, marketers and LNG importers, whose storage needs include both traditional seasonal storage services and short-term storage services. Pine Prairie is strategically positioned relative to several major market hubs, including the Henry Hub (the delivery point for New York Mercantile Exchange (NYMEX) natural gas futures contracts and located approximately 50 miles southeast of Pine Prairie), the Carthage Hub (located in East Texas), and the Perryville Hub (located in North Louisiana), and to existing and proposed LNG import and export facilities.

Pine Prairie s pipeline header system, which includes an aggregate of approximately 80 miles of 24-inch diameter pipe located within a 20-mile radius of Pine Prairie, is directly connected to eight large-diameter interstate pipelines through nine interconnects that service both conventional and unconventional natural gas production in Texas and Louisiana, including production from existing and emerging shale plays, as well as Gulf of Mexico production and LNG imports. These interconnects also provide direct or indirect access to each of the market hubs described above and to consumer and industrial markets in the Gulf Coast, Midwest, Northeast and Southeast regions of the United States. Pine Prairie s peak daily injection and withdrawal rates are 2.4 Bcf and 3.2 Bcf, respectively, and Pine Prairie has a total of 71,000 horsepower of compression capacity currently in service with another 27,500 horsepower of permitted capacity.

Southern Pines   pipeline header system, which includes an aggregate of 60 miles of 24-inch diameter pipe, is directly or indirectly connected to 8 major natural gas pipelines servicing the Gulf Coast, Northeast, Mid-Atlantic and Southeastern U.S. markets. Southern Pines   peak daily injection and withdrawal rates are 1.2 Bcf and 2.4 Bcf, respectively, and Southern Pines has a total of 48,000 horsepower of compression capacity currently in service.

Bluewater. Bluewater is located in the State of Michigan which contains more underground natural gas storage capacity than any other state in the U.S. according to EIA data, and primarily services seasonal storage needs throughout the Midwestern and Northeastern portions of the U.S. and the Southeastern portion of Canada. Accordingly, Bluewater s customers consist primarily of pipelines, utilities and marketers seeking seasonal storage services. Bluewater s 30-mile, 20-inch diameter pipeline header system is supported by 13,350 horsepower of compression and connects with three interstate and three natural gas utility pipelines that provide access to the major market hubs of Chicago, Illinois and Dawn, Ontario, which supply natural gas to eastern Ontario and the northeastern United States. These interconnects also provide access to natural gas utilities that serve local markets in Michigan and Ontario. Bluewater s peak daily injection and withdrawal rates are 0.5 Bcf and 0.8 Bcf, respectively.

12

Table of Contents

As indicated in the table above, Bluewater has total working gas storage capacity of approximately 26 Bcf in two depleted reservoirs and is permitted for an additional 3 Bcf of working gas storage capacity. We expect to increase Bluewater s working gas capacity by 2 Bcf ratably over a 8 to 9-year period in connection with an ongoing liquids removal project. Bluewater also leases third-party storage capacity and pipeline transportation capacity from time to time to increase its operational flexibility and enhance its service offerings. Bluewater has filed an application with the FERC to build a 20-inch pipeline that will be permitted for up to 300 MMcf per day and will connect its facility to a Canadian pipeline owned by an affiliate of Spectra Energy. The proposed pipeline is intended to replace a 12-inch pipeline that is permitted for up to 250 MMcf per day and is currently leased from Nova Chemical through January 2013. See Item 1A, Risk Factors Risks Related to our Business We may not receive the permits needed to complete construction of a pipeline that will replace the leased line that currently connects our Bluewater facility to markets in western Ontario.

Our Operations

We provide natural gas storage services to a broad mix of customers, including local gas distribution companies, or LDCs, electric utilities, pipelines, direct industrial users, electric power generators, marketers, producers, LNG importers and affiliates of such entities. Our storage rates are regulated under FERC rate-making policies which currently permit our facilities to charge market-based rates for our services.

We generate revenue primarily from the provision of fee-based gas storage services to our customers. For the year ended December 31, 2011, our total net revenues (total revenues less storage related costs, the cost of natural gas sold and fuel expense) were derived approximately 91% from fee-based storage activities (which includes system access fees collected at our Pine Prairie facility), approximately 7% from the activities of our dedicated marketing group and approximately 2% from other activities, which includes the sale of liquid hydrocarbons incidentally produced in connection with the operation of our depleted reservoir storage facilities at Bluewater and other fuel and derivative related net gains and losses. We categorize the majority of the revenue we generate as being derived from Firm Storage Services or Hub Services and Merchant Storage Activities. We also generate a portion of our net revenues from other sources as described below in Other Activities.

Firm Storage Services.
The majority of our net revenue from firm storage services is derived from contracts with initial terms that generally range from one year to 10 years in length and pursuant to which customers receive the assured or firm right to store gas in our facilities. Under our firm storage contracts, our customers are obligated to pay us fixed monthly capacity reservation fees, which are owed to us regardless of the actual storage capacity utilized. As of December 31, 2011, the weighted average remaining tenor of our existing portfolio of third party firm storage contracts was approximately 3.3 years. Firm storage services revenue also includes, when applicable, cycling fees based on the volume of natural gas nominated for injection and/or withdrawal, as well as a small portion of natural gas nominated for injection that we retain as compensation for our fuel use. Storage related costs consist of fees incurred to lease third-party storage and pipeline capacity and certain other costs we may incur. Additionally, we incur fuel expense at our facilities as we manage injection and deliverability capacity. For the year ended December 31, 2011, net revenue from firm storage services (firm storage services revenues net of applicable storage related costs and fuel expense) comprised approximately 85% of our total net revenues.

Hub Services and Merchant Storage Activities.
We also generate net revenue from the provision of hub services at our facilities and through the merchant storage activities of our commercial marketing group, which captures short term market opportunities by utilizing a portion of our storage capacity and engaging in related commercial marketing activities.

Our capacity to provide hub services is primarily dependent on our outstanding obligations to customers under firm storage services contracts. As a result, increases in our firm storage services obligations may limit our ability to provide hub services and vice versa. Hub services include (i) interruptible storage services pursuant to which customers receive only limited assurances regarding the availability of capacity in our storage facilities and pay fees based on their actual utilization of our assets, (ii) park and loan services and (iii) wheeling and balancing services pursuant to which customers pay fees for the right to move a volume of gas through our facilities from one interconnection point to another and true up their deliveries of gas to, or takeaways of gas from, our facilities. A portion of our revenues related to these activities may include fuel collections.

Our merchant storage activities generate revenue through the hedged purchase and sale of natural gas net of any storage related costs incurred. We utilize physical storage at our facilities and derivatives to hedge expected margin from these activities. Through these transactions, we seek to maintain a position that is substantially balanced between purchases on the one hand and sales or future delivery obligations on the other hand. Our general policy is (i) to purchase natural gas only in situations where we have a market for such gas, (ii) to utilize physical natural gas inventory and financial derivatives to manage

13

Table of Contents

and optimize seasonal and spread risks inherent in our operations and commercial management activities and to structure our transactions so that commodity price fluctuations will not have a material adverse impact on our cash flow and (iii) not to acquire or hold natural gas, futures contracts or other derivative products for the purpose of speculating on outright commodity price changes.

In connection with our hub services and merchant storage activities, we incur certain storage related costs. These costs consist of fees incurred to lease third-party pipeline capacity and storage and transaction costs associated with managing injection and deliverability capacity at our facilities. Costs associated with our leased pipeline capacity are subject to variation as the terms of these agreements typically contain certain fees which fluctuate based on actual volumes shipped in addition to monthly reservation fees. Also included in our storage related costs is fuel expense we incur as part of our short term activities.

For the year ended December 31, 2011, net revenue from hub services and merchant storage (hub services and natural gas sales revenues net of applicable storage related costs, fuel expense and the cost of natural gas sold) comprised approximately 12% of our total net revenues.

Other Activities.

We also generate revenue through certain fixed access fees collected at Pine Prairie and through the sale of crude oil and natural gas liquids produced in conjunction with the operation of our Bluewater facility, net of royalties and taxes. Additionally, we periodically sell any fuel-in-kind volumes in excess of actual volumes needed as fuel to operate facilities and reflect any gain or loss on such sales as a part of other revenues. For the year ended December 31, 2011, net revenue from such other activities comprised approximately 3% of our total net revenues.

Overall, we believe that the high percentage of our baseline cash flow derived from fixed-capacity reservation fees under multi-year contracts with a diverse portfolio of customers stabilizes our cash flow profile and substantially mitigates the risk to us of significant negative cash flow fluctuations caused by changing supply and demand conditions and other market factors.

Customers

As of December 31, 2011, Southern Pines had 15 customers with firm storage contracts and 33 customers with hub services contracts, Pine Prairie had 21 customers with firm storage contracts and 59 customers with hub services contracts and Bluewater had 13 customers with firm storage contracts and 75 customers with hub services contracts. Approximately 17% of our total revenues for the year ended December 31, 2011 was generated from physical sales of natural gas executed through Natural Gas Exchange Inc., a commodity exchange. No other customer accounted for greater than 10% of our total revenues for the year ended December 31, 2011.

Contracts

See Our Operations.

Competition

The principal elements of competition among storage facilities are rates, terms of service, types of service, supply and market access, and flexibility and reliability of service. An increase in competition in our markets could arise from new ventures or expanded operations from existing competitors.

Pine Prairie and Southern Pines compete with several regional high-deliverability storage facilities along the Gulf Coast as well as the storage services offered by interstate and intrastate pipelines that serve the same markets as Pine Prairie and Southern Pines, while Bluewater competes with several Midwest utility and pipeline storage providers.

Table of Contents

Natural Gas Regulation

PNG is subject to extensive laws and regulations. We are subject to regulatory oversight by numerous federal, state, and local regulatory agencies, many of which are authorized by statute to issue, and have issued, rules and regulations binding on the natural gas storage and pipeline industry, related businesses and market participants. The failure to comply with such laws and regulations can result in substantial penalties and fines. The regulatory burden increases our cost of doing business and, consequently, affects our profitability. Our historical and projected operating costs reflect the recurring costs resulting from compliance with these regulations, and we do not anticipate material expenditures in excess of these amounts in the absence of future acquisitions or changes in regulation, or discovery of existing but unknown compliance issues. We do not believe that we are affected by applicable laws and regulations in a significantly different manner than are our competitors.

The following is a summary of the kinds of regulation that may impact our operations. However, our unitholders should not rely on such discussion as an exhaustive review of all regulatory considerations affecting our operations.

Our facilities provide natural gas storage services in interstate commerce and are subject to comprehensive regulation by the Federal Energy Regulatory Commission (FERC) under the Natural Gas Act of 1938 (NGA). Pursuant to the NGA and FERC regulations, storage providers are prohibited from making or granting any undue preference or advantage to any person or subjecting any person to any undue prejudice or disadvantage or from maintaining any unreasonable difference in rates, charges, service, facilities, or in any other respect. The terms and conditions for services provided by our facilities are set forth in FERC approved tariffs. We have been granted market-based rate authorization for the services that our facilities provide. Market-based rate authority allows us to negotiate rates with individual customers based on market demand.

The FERC also has authority over the siting, construction, and operation of U.S. pipeline transportation and storage facilities and related facilities used in the transportation, storage and sale for resale of natural gas in interstate commerce, including the extension, enlargement or abandonment of such facilities. The FERC s authority extends to maintenance of accounts and records, terms and conditions of service, acquisition and disposition of facilities, initiation and discontinuation of services, imposition of creditworthiness and credit support requirements applicable to customers and relationships among pipelines and storage companies and certain affiliates. Our natural gas storage entities are required by the FERC to post certain information daily regarding customer activity, capacity and volumes on their respective websites. Additionally, the FERC has jurisdiction to impose rules and regulations applicable to all natural gas market participants including PNG Marketing and PAA Natural Gas Canada, to ensure market transparency. FERC regulations require that buyers and sellers of more than a de minimis volume of natural gas report annual numbers and volumes of relevant transactions to the FERC. Our facilities and marketing entities are subject to these annual reporting requirements.

Under the Energy Policy Act of 2005 (EPAct 2005) and related regulations, it is unlawful in connection with the purchase or sale of natural gas or transportation services subject to FERC jurisdiction to use or employ any device, scheme or artifice to defraud; to make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or to engage in any act or practice that operates as a fraud or deceit upon any person. EPAct 2005 gives the FERC civil penalty authority to impose penalties for certain violations of up to $1,000,000 per day for each violation. FERC also has the authority to order disgorgement of profits from transactions deemed to violate the NGA and the EPAct 2005.

Bluewater provides storage service by means of receipts or deliveries of natural gas at the international border with Canada or within the Province of Ontario. The importation and exportation of natural gas from and to the United States and Canada is subject to regulation by U.S. Customs and Border Protection, U.S. Department of Energy and the National Energy Board of Canada. Bluewater, PNG Marketing and PAA Natural Gas Canada have regulatory authorization to import and export natural gas from and to the Unites States and Canada.

Additional proposals and proceedings that might affect the natural gas industry are pending before Congress, the FERC, state commissions and the courts. The natural gas industry historically has been heavily regulated. New rules, orders, regulations or laws may be passed or implemented that impose additional costs, burdens or restrictions on us. We cannot give any assurance regarding the likelihood of such future rules, orders, regulations or laws or the effect they could have on our business, financial condition, and results of operations or ability to make distributions to our unitholders.

Environmental Matters

General. Our natural gas storage operations are subject to stringent and complex federal, state, and local laws and regulations governing environmental protection, including air emissions, water quality, wastewater discharges, and solid waste management. Such laws and regulations generally require us to obtain and comply with a wide variety of environmental registrations, licenses, permits, and other approvals. These laws and regulations may impose numerous obligations that are applicable to our operations, including the

acquisition of permits to conduct certain activities, increases in operating expenses or curtailment of certain operations to limit or prevent the release of materials from our facilities, the incurrence of capital expenditures associated with the installation of pollution control equipment, and the imposition of substantial liabilities for pollution resulting from our operations. 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 remedial obligations, and the issuance of injunctions limiting or preventing some or all of our operations.

We believe that we are in substantial compliance with existing federal, state, and local environmental laws and regulations and that such laws and regulations will not have a material adverse effect on our business, financial position, or results of operations. Nevertheless, the trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment. As a result, there can be no assurance of 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. The following is a discussion of some of the environmental laws and regulations that are applicable to our natural gas storage operations.

Waste Management. Our operations generate hazardous and non-hazardous solid wastes that are subject to the federal Resource Conservation and Recovery Act (RCRA) and comparable state laws and regulations, which impose detailed requirements for the handling, storage, treatment, and disposal of hazardous and non-hazardous solid wastes. For instance, RCRA imposes stringent limitations on the treatment, storage, transportation and disposal of hazardous wastes. Generators of hazardous wastes must also comply with certain standards for the accumulation and storage of hazardous wastes and meet recordkeeping and reporting requirements applicable to hazardous waste storage and disposal activities.

Site Remediation. The Comprehensive Environmental Response, Compensation and Liability Act (CERCLA, also known as Superfund) and comparable state laws and regulations impose liability (without regard to fault or the legality of the original conduct) on certain classes of persons responsible for the release of hazardous substances into the environment. Such classes of persons include current and prior owners or operators of the site where the release occurred and companies that disposed of, or arranged for the disposal of, hazardous substances found at offsite locations such as landfills. CERCLA also authorizes the Environmental Protection Agency (EPA) and, in some instances, third parties, to respond to threats to public health or the environment and seek recovery of response costs from responsible persons. Although natural gas is not classified as a hazardous substance under CERCLA, we may nonetheless handle hazardous substances within the meaning of CERCLA or similar state statutes in the course of our ordinary operations; as a result, we may be jointly and severally liable under CERCLA for all or part of the costs required to clean up sites where such hazardous substances have been released into the environment, natural resource damages, and the cost of certain health studies. Moreover, 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.

Air Emissions. Our operations are subject to the federal Clean Air Act (CAA) and comparable state laws and regulations. These laws and regulations regulate the emission 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 us to obtain pre-approval for the construction or modification of certain projects or facilities expected to result in significant air emissions, obtain and strictly comply with air permits containing various emissions and operational limitations, and/or utilize specific emission control technologies to limit our emissions. To comply with, maintain, or obtain our air emissions operating permits, we may be required to incur certain capital expenditures in the future for the purchase and installation of air pollution control equipment. For example, we may be required to supplement or modify our air emission control equipment and strategies due to changes in state implementation plans for controlling air emissions or more stringent regulation of hazardous air pollutants.

Noise Emissions. The Partnership is subject to a number of federal, state and local laws, regulations, ordinances and standards that govern noise emissions from our facilities. The U.S. Occupational Safety & Health Administration (OSHA) has established maximum noise levels for occupational exposure and the Partnership undertakes various noise protection efforts, including administrative and engineering controls, in order to achieve these standards and protect our employees. The Partnership has also implemented a hearing conservation program for our employees who may be exposed to noise in the workplace and provides personal protective equipment as necessary.

The Partnership must also comply with federal guidelines and state and local regulations regarding sound that is transmitted from our facilities and our construction projects to the surrounding community. At the federal level, the EPA has identified a maximum sound level that will not adversely affect public health and welfare. Although allowed noise emission levels are typically established on a project by project basis and depend to a certain extent on pre-existing ambient noise levels for a given project, the FERC has adopted the EPA s maximum sound level as a general goal for new gas compressor stations, pipeline construction and other operations regulated by the FERC. In addition, sound generated from construction and operation of our facilities and pipelines is also regulated in some jurisdictions at the county and municipal level, and depending on the circumstances, such local requirements may be more or less stringent than applicable federal rules.

16

Table of Contents

Water Discharges. The Clean Water Act (CWA) and analogous state laws regulate the discharge of pollutants, including spills and leaks of oil and other substances, into waters of the United States. The CWA prohibits the discharge of pollutants into regulated waters, except in accordance with the terms of a permit issued by the EPA or analogous state agency. The CWA also regulates the discharge of storm water runoff from certain industrial facilities. Accordingly, some states require industrial facilities to obtain and maintain storm water discharge permits, which require monitoring and sampling of storm water runoff from such facilities.

Safe Drinking Water Act. As part of our operations, we employ underground injection wells to inject natural gas into our underground storage facilities. Such operations are subject to the Safe Drinking Water Act (SDWA) and analogous state laws, which regulate drinking water quality in the United States, including above ground and underground sources designated for actual or potential drinking water use. In particular, to protect underground sources of drinking water, the Underground Injection Control Program (UIC Program) of the SDWA regulates the construction, operation, maintenance, monitoring, testing, and closure of underground injection wells. The UIC Program also requires that all underground injection wells be authorized, either under the general rules of the UIC Program or through specific permits. In most jurisdictions, states have primary enforcement authority over the implementation of the UIC Program, including the issuance of permits.

Climate Change. In December 2009, the EPA published its findings that emissions of greenhouse gases (GHGs), including carbon dioxide and methane, present a danger to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the Earth s atmosphere and other climatic changes. Based on these findings, in 2010 the EPA adopted two sets of regulations that restrict emissions of GHGs under existing provisions of the CAA, including one that requires a reduction in emissions of GHGs from motor vehicles and another that requires construction and operating permit reviews for GHG emissions from certain large stationary sources, including, among others, onshore and offshore oil and natural gas production facilities. Also, Congress has from time to time considered adopting legislation to reduce emissions of GHGs, and almost one-half of the states already have taken legal measures to reduce emissions of GHGs, primarily through the planned development of GHG emission inventories and/or regional GHG cap-and-trade programs. The adoption of any legislation or regulation that requires reporting of GHGs or otherwise restricts emissions of GHGs from our equipment and operations could require us to incur significant added costs to reduce emissions of GHGs or could adversely affect demand for natural gas. Finally, some scientists have concluded that increasing concentrations of GHGs in the Earth s atmosphere may produce climate changes that could have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climatic events; if such effects were to occur, they could have an adverse effect on our operations.

Pipeline Safety

As part of our natural gas storage operations, we own and operate pipeline header systems connecting our natural gas storage facilities to various interstate pipelines. As a result, our pipeline operations are subject to regulation by the Pipeline and Hazardous Materials Safety Administration (PHMSA) pursuant to the Natural Gas Pipeline Safety Act of 1968 (NGPSA). The NGPSA regulates safety requirements in the design, installation, testing, construction, operation and maintenance of gas pipeline facilities. The NGPSA has since been amended by the Pipeline Safety Act of 1992, the Pipeline Safety Improvement Act of 2002, the Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006, and, most recently, the Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011. These amendments, along with implementing regulations more recently adopted by PHMSA, have imposed additional safety requirements on pipeline operators such as the development of a written qualification program for individuals performing covered tasks on pipeline facilities and the implementation of pipeline integrity management programs. These integrity management plans require more frequent inspections and other preventative measures to ensure pipeline safety in high consequence areas, such as high population areas, areas unusually sensitive to environmental damage, and commercially navigable waterways. Accordingly, we will continue to focus on pipeline integrity management for any of the pipelines we currently own or acquire in the future, and significant additional expenses could be incurred if new or more stringent pipeline safety requirements are implemented. We believe that our operations are in substantial compliance with all existing federal, state, and local pipeline safety laws and regulations and that such laws and regulations will not have a material adverse effect on our business, financial position, or results of operations.

On December 13, 2011, the United States Congress passed the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (the Act). The President signed the Act into law on January 3, 2012. Under the Act, maximum civil penalties for certain violations have been increased from $100,000 to $200,000 per violation per day, and from a total cap of $1 million to $2 million. In addition, the Act reauthorizes the federal pipeline safety programs of PHMSA through September 30, 2015, and directs the Secretary of Transportation to undertake a number of reviews, studies and reports, some of which may result in additional natural gas and hazardous liquids pipeline safety rulemaking. Some of these directives include:

Table of Contents

The Secretary of Transportation must revise regulations establishing time limits for notification of pipeline facility accidents and incidents to a minimum of not more than 1 hour after discovery of an accident or incident;

Within 12 months, the Secretary of Transportation must submit to Congress a report providing information on the total number of authorized full-time positions for pipeline inspection and enforcement at the PHMSA, the total number of positions not filled, the action being taken to fill the vacant positions and any additional inspection and enforcement resource needs of the PHMSA;

Within 18 months, the Secretary of Transportation must conduct an evaluation to determine whether integrity management system requirements already in place for pipelines in High Consequence Areas (HCAs) should be expanded to pipelines beyond HCAs;

Within two years, the Secretary of Transportation must submit to Congress a report on the results of a review of existing federal and state regulations for gas and hazardous liquid gathering lines located offshore, including within inlets of the Gulf of Mexico, for the purpose of determining whether the Secretary should issue regulations subjecting offshore gathering lines to the same standards and regulations as other hazardous liquid gathering lines; and

Within two years, the Secretary of Transportation must determine whether to require the use of automatic or remote-controlled shut-off valves on new and entirely replaced transmission pipeline facilities.

A number of the provisions of the Act have the potential to cause owners and operators of pipeline facilities to incur significant capital expenditures and/or operating costs. Any additional requirements resulting from these directives are not expected to impact us differently than our competitors. We will work closely with our industry associations to participate with and monitor DOT-PHMSA s efforts.

In December 2009, PHMSA finalized a new rule dictating the shape and content of new control room management programs for hazardous liquid, gas transmission and distribution pipelines. The rule addresses human factors, including fatigue and other aspects of control room management for pipelines where controllers use supervisory control and data acquisition systems. The new rule became effective on February 1, 2010 and requires that control room management plans be written by August 1, 2011, which was completed on time by the Partnership. Implementation of certain aspects such as fatigue training for Controllers and Supervisors, Change Management, Operating Experience and establishing Shift Change procedures was required and completed by October 1, 2011. Implementation for the remaining aspects of the rule is required by August 1, 2012. We have already incorporated many of the new rule s requirements into our control room operations and we anticipate fully implementing the remaining provisions prior to the established deadline.

If approved by PHMSA, states may assume responsibility for enforcing federal interstate pipeline regulations as agents for PHMSA and conduct inspections of intrastate pipelines. In practice, states vary in their authority and capacity to address pipeline safety. We do not anticipate any significant issues in complying with applicable state laws and regulations.

The DOT has issued guidelines with respect to securing regulated facilities against terrorist attack. We have instituted security measures and procedures in accordance with such guidelines to enhance the protection of certain of our facilities. We cannot provide any assurance that these security measures would fully protect our facilities from an attack.

Occupational Safety and Health

Our operations are subject to a number of federal and state laws and regulations, including the federal OSHA and comparable state statutes designed to protect the health and safety of workers. The OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act, and comparable state statutes require that information be maintained concerning hazardous materials used or produced in our operations and that such information be provided to employees, state and local governmental authorities, and the public. Our operations are also subject to OSHA Process Safety Management regulations, which are designed to prevent or minimize the consequences of catastrophic releases of toxic, reactive, flammable or explosive chemicals. These regulations apply to any process that involves a chemical at or above specified thresholds or any process that involves 10,000 pounds or more of a flammable liquid or gas in one location. We believe that our operations are in substantial compliance with all existing federal, state, and local occupations health and safety laws and regulations and that such laws and regulations will not have a material adverse effect on our business, financial position, or results of operations.

Title to Properties and Rights-of-Way

Our real property falls into two categories: (1) parcels that we own in fee and (2) parcels in which our interest derives from leases, easements, rights-of-way, permits or licenses from landowners or governmental authorities permitting the use of such land for our operations. Portions of the land on which our facilities are located are owned by us in fee title, and we believe that we have satisfactory title to these lands. The remainder of the land on which our major facilities are located are held by us (or entities in which we own an interest) pursuant to leases between us, as lessee, and the fee owner of the lands, as lessors. We believe that we have satisfactory leasehold estates to such lands. We have no knowledge of any material challenge to the underlying fee title of any material lease, easement, right-of-way, permit or license held by us or to our title to any material lease, easement, right-of-way, permit or license, and we believe that we have satisfactory title to all of our material leases, easements, rights-of-way, permits and licenses. See Our Assets.

Insurance

We share insurance coverage with PAA and we reimburse PAA s general partner pursuant to the terms of the omnibus agreement. To the extent PAA experiences covered losses under the insurance policies, the limit of our coverage for potential losses may be decreased. Our insurance program includes general liability insurance, auto liability insurance, worker s compensation insurance, and property insurance in amounts which management believes are reasonable and appropriate. In addition, the insurance policies are subject to deductibles that we consider reasonable and not excessive.

A natural gas storage facility, associated pipeline header system, and gas handling and compression facilities may experience damage as a result of an accident, natural disaster or terrorist activity. These hazards can cause personal injury and loss of life, severe damage to and destruction of property, base gas, and equipment, pollution or environmental damage and suspension of operations. Our insurance does not cover every potential risk associated with operating natural gas storage facility, associated pipeline header system, and gas handling and compression facilities, including the potential loss of significant revenues. The overall trend in the insurance industry appears to be a contraction in the breadth and depth of available coverage, while costs, deductibles and retention levels have increased. Absent a material favorable change in the insurance markets, this trend is expected to continue as we continue to grow and expand. As a result, we anticipate that we will elect to self-insure more of our activities or incorporate higher retention in our insurance arrangements.

The occurrence of a significant event not fully insured, indemnified or reserved against, or the failure of a party to meet its indemnification obligations, could materially and adversely affect our operations and financial condition. We believe we are adequately insured for public liability and property damage to others with respect to our operations. With respect to all of our coverage, we may not be able to maintain adequate insurance in the future at rates we consider reasonable. In addition, although we believe that we have established adequate reserves to the extent that such risks are not insured, costs incurred in excess of these reserves may be higher and may potentially have a material adverse effect on our financial conditions, results of operations or cash flows.

Employees

Plains All American GP LLC employs all of our personnel. We are managed and operated by the directors and officers of our general partner. We rely on an omnibus agreement with Plains All American GP LLC to provide us with employees needed to carry out our operations. As of December 31, 2011, 83 full time employees of Plains All American GP LLC devoted substantially all of their time to carrying out our operations.

Table of Contents

Summary of U.S. Income Tax Considerations

The following is a brief summary of material tax considerations of owning and disposing of common units, however, the tax consequences of ownership of common units depends in part on the owner s individual tax circumstances. It is the responsibility of each unitholder, either individually or through a tax advisor, to investigate the legal and tax consequences, under the laws of pertinent U.S. federal, states and localities, of the unitholder s investment in us. Further, it is the responsibility of each unitholder to file all U.S. federal, state, provincial and local tax returns that may be required of the unitholder.

Partnership Status; Cash Distributions

We are treated for federal income tax purposes as a partnership based upon our meeting the Qualifying Income Exception imposed by Section 7704 of the Internal Revenue Code (the Code), which we must meet each year. The owners of our common units are considered partners in the Partnership so long as they do not loan their common units to others to cover short sales or otherwise dispose of those units. Accordingly, we are not liable for U.S. federal income taxes, and a common unitholder is required to report on the unitholder s federal income tax return the unitholder s share of our income, gains, losses and deductions. In general, cash distributions to a common unitholder are taxable only if, and to the extent that, they exceed the tax basis in the common units held.

Partnership Allocations

In general, our income and loss is allocated to the general partner and the unitholders for each taxable year in accordance with their respective percentage interests in the Partnership, as determined annually and prorated on a monthly basis and subsequently apportioned among the general partner and the unitholders of record as of the opening of the first business day of the month to which they relate, even though unitholders may dispose of their units during the month in question. In determining a unitholder s U.S. federal income tax liability, the unitholder is required to take into account the unitholder s share of income generated by us for each taxable year of the Partnership ending with or within the unitholder s taxable year, even if cash distributions are not made to the unitholder. As a consequence, a unitholder s share of our taxable income (and possibly the income tax payable by the unitholder with respect to such income) may exceed the cash actually distributed to the unitholder by us. Any time incentive distributions are made to the general partner, gross income will be allocated to the recipient to the extent of those distributions.

Basis of Common Units

A unitholder s initial tax basis for a common unit is generally the amount paid for the common unit and the unitholder s share of our nonrecourse liabilities (or liabilities for which no partner bears the economic risk of loss). A unitholder s basis is generally increased by the unitholder s share of our income and by any increases in the unitholder s share of our nonrecourse liabilities. That basis will be decreased, but not below zero, by the unitholder s share of our losses and distributions (including deemed distributions due to a decrease in the unitholder s share of our nonrecourse liabilities).

Limitations on Deductibility of Partnership Losses

The deduction by a unitholder of that unitholder s allocable share of our losses will be limited to the amount of that unitholder s tax basis in his or her common units and, in the case of an individual unitholder or a corporate unitholder who is subject to the at-risk rules (generally, certain closely-held corporations), to the amount for which the unitholder is considered to be at-risk with respect to our activities, if that is less than the unitholder s tax basis. A unitholder must recapture losses deducted in previous years to the extent that distributions cause the unitholder s at-risk amount to be less than zero at the end of any taxable year. Losses disallowed to a unitholder or recaptured as a result of these limitations will carry forward and will be allowable as a deduction to the extent that his at-risk amount is subsequently increased, provided such losses do not exceed such unitholder s tax basis in his common units. Upon the taxable disposition of a common unit, any gain recognized by a unitholder can be offset by losses that were previously suspended by the at-risk limitation but may not be offset by losses suspended by the basis limitation. Any loss previously suspended by the at-risk limitation in excess of that gain could no longer be used.

In addition to the basis and at-risk limitation described above, in the case of taxpayers subject to the passive loss rules (generally, individuals and certain closely held corporations), any partnership losses generated by us are only available to offset future income generated by us and cannot be used to offset income from other activities, including passive activities or investments. Any losses unused or suspended by virtue of the passive loss rules may be fully deducted if the unitholder disposes of all of the unitholder s common units in a taxable transaction with an unrelated party.

Section 754 Election

We have made the election provided for by Section 754 of the Code, which will generally result in a unitholder being allocated income and deductions calculated by reference to the portion of the unitholder s purchase price attributable to each asset of the Partnership.

Disposition of Common Units

A unitholder who sells common units will recognize gain or loss equal to the difference between the amount realized and the adjusted tax basis of those common units. A unitholder may not be able to trace basis to particular common units for this purpose. Thus, distributions of cash from us to a unitholder in excess of the income allocated to the unitholder will, in effect, become taxable income if the unitholder sells the common units at a price greater than the unitholder s adjusted tax basis even if the price is less than the unitholder s original cost. Moreover, a portion of the amount realized (whether or not representing gain) will be taxed as ordinary income due to potential recapture items, including depreciation recapture. In addition, because the amount realized includes a unitholder s share of our nonrecourse liabilities, a unitholder may incur a tax liability in excess of the amount of cash the unitholder receives from the sale.

State, Local and Other Tax Considerations

In addition to federal income taxes, unitholders will likely be subject to other taxes, such as state and local income taxes, unincorporated business taxes, and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which a unitholder resides or in which we conduct business or own property. A unitholder may also be required to file state income tax returns and to pay taxes in various states. A unitholder may be subject to interest and penalties for failure to comply with such requirements. In certain states, tax losses may not produce a tax benefit in the year incurred (if, for example, we have no income from sources within that state) and also may not be available to offset income in subsequent taxable years. Some states may require us, or we may elect, to withhold a percentage of income from amounts to be distributed to a unitholder who is not a resident of the state. Withholding, the amount of which may be more or less than a particular unitholder s income tax liability owed to a particular state, may not relieve the unitholder from the obligation to file an income tax return in that state. Amounts withheld may be treated as if distributed to unitholders for purposes of determining the amounts distributed by us.

Our Canadian operations are conducted in an entity that is treated as a corporation for Canadian tax purposes (flow through for U.S. tax purposes.) Although we are subject to Canadian federal and provincial taxes, the impact to the year ended December 31, 2011 was immaterial.

Ownership of Common Units by Tax-Exempt Organizations and Certain Other Investors

An investment in common units by tax-exempt organizations (including IRAs and other retirement plans) and foreign persons raises issues unique to such persons. Virtually all of our income allocated to a unitholder that is a tax-exempt organization is unrelated business taxable income and, thus, is taxable to such a unitholder. A unitholder who is a nonresident alien, non-U.S. corporation or other non-U.S. person is regarded as being engaged in a trade or business in the United States as a result of ownership of a common unit and, thus, is required to file federal income tax returns and to pay tax on the unitholder s share of our taxable income. Finally, distributions to foreign unitholders are subject to federal income tax withholding at the highest applicable rate.

Available Information

We make available, free of charge on our Internet website (http://www.pnglp.com), our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act as soon as reasonably practicable after we electronically file the material with, or furnish it to, the Securities and Exchange Commission (SEC).

Table of Contents

Item 1A. Risk Factors
Risks Related to Our Business

We may not have sufficient cash following the establishment of reserves and payment of fees and expenses, including cost reimbursements to our general partner, to enable us to pay the existing distribution of $1.43 per unit or the minimum quarterly distribution of $1.35 per unit to holders of our common units and Series A subordinated units.

We may not have sufficient available cash from distributable cash flow each quarter to enable us to pay the existing distribution of $1.43 per unit or the minimum quarterly distribution of $1.35 per unit. The amount of cash we can distribute on our units principally depends upon the amount of cash we generate from our operations, which will fluctuate from quarter to quarter based on, among other things:

- the rates we charge for storage services and the amount of natural gas storage services our customers purchase from us;
- the overall balance between the supply of and demand for natural gas, on a seasonal and long-term basis, which impacts the level of demand for the natural gas storage services we provide and the rates we are able to charge for such services;
- our ability to realize expected margins from our merchant storage activities due to natural gas price spreads and volatility levels, among other factors;
- regulatory action affecting the rates we can charge for the services we provide, the demand for natural gas, the supply of natural gas, our ability to expand our facilities, how we contract for services, our existing contracts, our operating and capital costs and our operating flexibility;
- the creditworthiness of our customers;
- the level of competition from other providers of natural gas storage services;
- the level of our operating and maintenance and general and administrative costs; and
- prevailing economic conditions.

In addition, the actual amount of cash we will have available for distribution will depend on other factors, some of which are beyond our control, including:

- the level of capital expenditures we make;
- the cost of acquisitions;
- our debt service requirements and other liabilities;

- fluctuations in our working capital needs;
- our ability to borrow funds and access capital markets;
- restrictions contained in debt agreements to which we are a party; and
- the amount of cash reserves established by our general partner.

For a description of additional restrictions and factors that may affect our ability to make cash distributions, see Item 5. Market for Registrant s Common Units, Related Unitholder Matters and Issuer Purchases of Equity Securities.

The amount of cash we have available for distribution to holders of our common units and Series A subordinated units depends primarily on our cash flow rather than on our profitability, which may prevent us 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 will be affected by non-cash items. As a result, we may make cash distributions during periods when we record losses for financial accounting purposes and may not make cash distributions during periods when we record net earnings for financial accounting purposes.

We may not be able to maintain or replace expiring storage contracts.

Our primary exposure to market risk occurs at the time our existing storage contracts expire and are subject to renegotiation and renewal and as we bring on additional working capacity that is uncontracted. As of December 31, 2011, the weighted average remaining tenor of our existing portfolio of firm storage contracts, including binding precedent agreements, is approximately 2.4 years at Pine Prairie, approximately 1.9 years at Bluewater and approximately 5.5 years at Southern Pines. Over the last eighteen months, conditions in the gas storage market have deteriorated and the rates under certain of these contracts are higher than current market rates. The extension or replacement of existing contracts, and entering into new contracts, could be, and in some cases has already been, adversely impacted by a number of factors beyond our control, including:

- an extended period of reduced natural gas price volatility;
- a reduction in the difference between winter and summer prices on the natural gas futures market, sometimes referred to as the seasonal spread, due to real or perceived changes in supply and demand fundamentals;
- a decrease in demand for natural gas storage in the markets we serve;
- increased competition for storage in the markets we serve; and
- higher interest rates, which increase inventory carrying costs for our customers.

Table of Contents

The failure to extend or replace a significant portion of our existing contracts, the extension or replacement of such contracts at unfavorable or lower rates, or the failure to enter into favorable contracts with respect to incremental working capacity, could have a material adverse effect on our business, financial condition, results of operations and ability to make distributions.

Increased competition from other companies that provide natural gas storage services or services that can substitute for storage services could have a negative impact on the demand for our services, which could adversely affect our financial results.

We compete primarily with other providers of natural gas storage services that own or operate salt-dome, depleted reservoir and/or converted aquifer gas storage facilities. Such competitors include independent storage developers and operators, local distribution companies, utilities, interstate and intrastate gas transmission companies with storage facilities connected to their pipelines and midstream energy companies. FERC has generally adopted policies that favor the development of new storage projects and there are numerous projects, including expansions of existing facilities and greenfield construction projects, at various stages of development in the markets where we operate. According to FERC data, since 2000, permits have been issued by the FERC for new interstate gas storage facilities or expansions in the Gulf Coast (excluding intrastate facilities and FERC pre-filings for additional storage capacity) representing aggregate additional working gas capacity of approximately 740 Bcf. These projects, if developed and placed into service, may compete with our storage operations. The principal elements of competition among storage facilities are rates, terms of service, types of service, deliverability, supply and market access, flexibility and reliability of service.

We also compete with certain pipelines, marketers and LNG facilities that provide services that can substitute for certain of the storage services we offer. In addition, natural gas as a fuel competes with other forms of energy available to end-users, including electricity, coal and liquid fuels. Increased demand for such forms of energy at the expense of natural gas could lead to a reduction in demand for natural gas storage services.

All of these competitive pressures could make it more difficult for us to retain our existing customers and/or attract new customers as we seek to expand our business. This could have a material adverse effect on our business, financial condition, results of operations and ability to make distributions. In addition, competition could intensify the negative impact of factors that decrease demand for natural gas storage in our markets, such as adverse economic conditions, weather, higher fuel costs and taxes or other governmental or regulatory actions that directly or indirectly increase the cost or limit the use of natural gas.

Our natural gas storage operations are subject to regulation by federal, state and local regulatory authorities; regulatory measures adopted by such authorities could have a material adverse effect on our business, financial condition, results of operations and ability to make distributions.

Our natural gas storage operations are subject to federal, state and local laws and regulations administered by a number of authorities. Because we provide natural gas storage services in interstate commerce, our natural gas storage facilities are subject to comprehensive regulation by the FERC under the NGA.

Pursuant to the NGA and FERC regulations, we are prohibited from making or granting any undue preference or advantage to any person or subjecting any person to any undue prejudice or disadvantage or from maintaining any unreasonable difference in rates, charges, service, facilities, or in any other respect. Any successful complaint or protest against us could have an adverse impact on our revenues associated with providing storage services.

The terms and conditions for services provided by our facilities are set forth in FERC-approved tariffs. We have been granted market-based rate authorization for the services that our facilities provide. Market-based rate authority allows us to negotiate rates with individual customers based on market demand. A storage provider granted market-based rate authorization is required to notify FERC of significant changes occurring in its market power status, Significant changes include, but are not limited to, the storage provider expanding its storage capacity beyond the amount authorized in applicable certificate orders, the storage provider acquiring transportation facilities or additional storage capacity, an affiliate of the storage provider providing storage or transportation services in the same market area, and the storage provider or an affiliate acquiring an interest in or being acquired by an interstate pipeline.

Should we fail to comply with applicable FERC-administered statutes, rules, regulations and orders, we could be subject to substantial penalties and fines. Under the EPAct 2005, FERC has civil penalty authority under the NGA to impose penalties for certain violations of up to $1,000,000 per day for each violation. FERC also has the authority to order disgorgement of profits from transactions deemed to violate the NGA and the EPAct 2005. See Items 1 and 2. Business and Properties Regulation.

23

Table of Contents

Finally, new rules, orders, regulations or laws may be passed or implemented that impose additional costs, burdens or restrictions on us. We cannot give any assurance regarding the likelihood of such future rules, orders, regulations or laws or the effect they could have on our business, financial condition, results of operations or ability to make distributions to our unitholders.

Our sales of natural gas, and related hedging activities, expose us to potential regulatory risks.

The Federal Trade Commission, the FERC and the Commodity Futures Trading Commission hold statutory authority to monitor certain segments of the physical and futures energy commodities markets. These agencies have imposed broad regulations prohibiting fraud and manipulation of such markets. With regard to our physical sales of natural gas and any related transportation and/or hedging activities that we undertake, we are required to observe the market-related regulations enforced by these agencies, which hold substantial enforcement authority. Our sales may also be subject to certain reporting and other requirements. Additionally, to the extent that we enter into transportation contracts with natural gas pipelines that are subject to FERC regulation, we are subject to FERC requirements related to use of such capacity. Any failure on our part to comply with the FERC s regulations and policies, or with an interstate pipeline s tariff, could result in the imposition of civil and criminal penalties. Failure to comply with such regulations, as interpreted and enforced, could have a material adverse effect on our business, results of operations, financial condition and our ability to make cash distributions to our unitholders.

A prolonged period of stabilized natural gas prices and/or low levels of volatility could have a negative impact on our business.

Historically, natural gas prices have been seasonal and volatile, which has enhanced demand for our storage services. The storage business has benefited from significant price fluctuations resulting from seasonal price sensitivity, which affects demand for our services and the rates we are able to charge for such services. On a system-wide basis, natural gas is typically injected into storage between April and October when natural gas prices are generally lower and withdrawn during the winter months of November through March when natural gas prices are typically higher. However, due to a variety of factors (including relatively flat consumption over the last year, increased supplies due to shale production, net increases in storage capacity and lower basis differentials due to transportation infrastructure expansion), the volatility and seasonality of natural gas prices for the 12-18 months ended December 31, 2011 have been low relative to prior time periods. If these conditions persist, the demand for our services and the margin that we will be able to generate in connection with the sale of such services will remain under pressure and may decline.

Table of Contents

Any significant and prolonged change in or stabilization of natural gas prices could have a negative impact on our business.

Historically, natural gas prices have been seasonal and volatile, which has enhanced demand for our storage services. The storage business has benefited from significant price fluctuations resulting from such seasonal price sensitivity, which impacts the level of demand for our services and the rates we are able to charge for such services. On a system-wide basis, natural gas is typically injected into storage between April and October when natural gas prices are generally lower, and withdrawn during the winter months of November through March when natural gas prices are typically higher. However, the market for natural gas may not continue to experience volatility and seasonal price sensitivity in the future at the levels previously seen. This has been the case generally for the 12-18 months ended December 31, 2011, and if volatility and seasonality in the natural gas industry remain low relative to prior time periods, whether due to increased natural gas production or otherwise, the demand for our services and the prices that we will be able to charge for those services may decline.

Our storage business depends on third-party pipelines connected to our storage facilities, and we could be negatively impacted by circumstances beyond our control that temporarily or permanently interrupt the operation of such pipelines.

We depend on the continued operation of third-party pipelines and other facilities that provide delivery options to and from our storage facilities. Because we do not own the pipelines that are interconnected to our facilities, their continued operation is not within our control. If any of the pipelines to which we are connected were to become unavailable for current or future withdrawals or injections of natural gas due to repairs, damage to the facility, lack of capacity or any other reason, our ability to operate efficiently and satisfy our customer s needs could be compromised, thereby potentially reducing our revenues. Any temporary or permanent interruption at any key pipeline or other interconnect point with our gas storage facilities that caused a material reduction in the storage services provided by us could have a material adverse effect on our business, financial condition, results of operation and ability to make distributions.

In addition, the rates charged by pipelines interconnected with our storage facilities for transportation to and from our facilities affects the utilization and value of the storage services we provide. Significant changes in the rates charged by these pipelines or their competitors could have a material adverse effect on our business, financial condition, results of operations and ability to make distributions.

We may not be able to achieve our current expansion plans at our facilities on economically viable terms.

Our 2012 expansion plans include the addition of 16 Bcf of working gas storage capacity at our Gulf Coast Facilities. These facilities are permitted for an aggregate of 120 Bcf of capacity, consisting of 80 Bcf at Pine Prairie and 40 Bcf at Southern Pines. In connection with our expansion efforts at these facilities, we may encounter difficulties in the drilling required to access subsurface storage caverns, the drilling of raw water wells or salt water disposal wells and the completion of the wells. These risks include the following:

- unexpected operational events;
- adverse weather conditions;
- facility or equipment malfunctions or breakdowns;
- unusual or unexpected geological formations;
- drill bit or drill pipe difficulties;
- collapses of wellbore, casing or other tubulars or other loss of drilling hole;
- unexpected problems associated with filling the caverns with base gas and conducting pressure and mechanical integrity tests;

unexpected problems associated with leaching the caverns, filtration of extracted water and offsite disposal of water; and

risks associated with subcontractors services, supplies, cost escalation and personnel.

Specifically, the creation of a salt-cavern storage facility requires sourcing, injecting, withdrawing and disposing of significant volume of water. For example, to create 10 Bcf of working capacity, a salt cavern requires approximately 72 million barrels of raw water supply and an equivalent volume of salt water disposal. Additionally, the rate of access to raw water and the rate of disposal of salt water have a direct impact on the time it takes to create a salt cavern. Any physical or regulatory restriction imposed on our current operations with respect to accessing raw water or disposing of salt water would have an adverse impact on our ability to timely and fully expand our facilities at Pine Prairie or Southern Pines. Additionally, the occurrence of uninsured or under-insured losses, delays or operating cost overruns associated with these drilling efforts could have a negative impact on our operations and financial results.

We may not receive the permits needed to complete construction of a pipeline that will replace the leased line that currently connects our Bluewater facility to markets in western Ontario.

Our Bluewater facility is connected to western Ontario markets through a leased pipeline that crosses the St. Clair river in Northern Michigan and connects to a pipeline owned by St. Clair Pipelines, an affiliate of Spectra Energy. Bluewater has been notified by the lessor of such pipeline that the lease will terminate in January 2013. Bluewater and an affiliate of Spectra Energy have entered into agreements to jointly construct a new line that will replace the existing line by January 2013. Construction of the replacement line requires FERC approval, a Presidential permit and approvals from applicable Canadian authorities. No assurances can be given that such approvals and permits will be received or that they will be received on a timely basis. Failure to receive such permits, or a significant delay in their receipt, could have a negative impact on Bluewater s ability to access markets in western Ontario, either through increased costs, lost business opportunities or both.

We are exposed to the credit risk of our customers in the ordinary course of our business.

As a normal part of our business we extend credit to our customers. As a result, we are exposed to the risk of loss resulting from the nonpayment and/or nonperformance of our customers. Although we have established credit policies that include assessing the creditworthiness of our customers and requiring appropriate terms or credit support from them based on the results of such assessments, there can be no assurance that we have adequately assessed the creditworthiness of our existing or future customers or that there will not be unanticipated deterioration in their creditworthiness. Resulting nonpayment and/or nonperformance by our customers could have a material adverse effect on our business, financial condition, results of operation and ability to make distributions.

Additionally, in instances where we loan natural gas to third parties, the magnitude of our credit risk is significantly increased, as the failure of the third party to return the loaned volumes would result in losses equal to the full value of the loaned natural gas rather than, in the case of firm storage or hub services contracts, losses equal to fees on volumes nominated for injection or withdrawal.

For various operating and commercial reasons, we may not be able to perform all of our obligations under our contracts, which could lead to increased costs and negatively impact our financial results.

Various operational and commercial factors could result in an inability on our part to satisfy our contractual commitments and obligations. For example, in connection with our provision of firm storage services and hub services to our customers, we enter into contracts that obligate us to honor our customers requests to inject gas into our storage facilities, withdraw gas from our facilities and wheel gas through our facilities, in each case subject to volume, timing and other limitations set forth in such contracts. The following factors could adversely impact our ability to perform our obligations under these contracts:

a failure on the part of our storage facilities to perform as we expect them to, whether due to malfunction of equipment or facilities or realization of other operational risks;

a failure on our part to create incremental storage capacity at our facilities due to reduced leaching rates, operational or other factors;

the operating pressure of our storage facilities (affected in varying degree, depending on the type of storage cavern, by total volume of working and base gas, and temperature);

a variety of commercial decisions we make from time to time in connection with the management and operation of our storage facilities. Examples include, without limitation, decisions with respect to matters such as (i) the aggregate amount of commitments we are willing to make with respect to wheeling, injection, and withdrawal services, which could exceed our capabilities at any given time for various reasons, (ii) the timing of scheduled and unplanned maintenance or repairs, which can impact equipment availability and capacity, (iii) the schedule for and rate at which we conduct leaching activities at our facilities in connection with the creation of new salt caverns or the expansion of existing caverns, which can impact the amount of storage capacity we have available to satisfy our customers requests, (iv) the timing and aggregate volume of any base gas park and/or loan transactions we consummate, which can directly affect the operating pressure of our storage facilities and (v) the amount of compression capacity and other gas handling equipment that we install at our facilities to support gas wheeling, injection and withdrawal activities; and

adverse operating conditions due to hurricanes, extreme weather events or conditions, and operational problems or issues with third party pipelines, storage or production facilities.

Although we manage and monitor all of these various factors in connection with the ongoing operation of our natural gas storage facilities with the goal of performing all of our contractual commitments and obligations and optimizing our revenue, one or more of the above factors may adversely impact our ability to satisfy our injection, withdrawal or wheeling obligations under our storage contracts. In such event, we may be liable to our customers for losses or damages they suffer and/or we may need to incur costs or expenses in order to permit us to satisfy our obligations.

Our cash receipts and financial results are usually lower in the second and third quarters of the calendar year, which may, depending on the level of our cash reserves, require us to borrow money in order to make distributions to the holders of our common units and Series A subordinated units.

Our cash expenditures related to our merchant storage activities are generally highest during summer months, and our cash receipts from such activities are highest during winter months. As a result, our results of operations for the summer are generally lower than for the winter. With lower cash flow during the second and third calendar quarters, depending on the level of our available cash reserves from prior quarters, we may be required to borrow money in order to pay distributions to the holders of our common units and Series A subordinated units.

Our marketing activities could result in financial losses. Our risk management policies cannot eliminate all risks and any non-compliance with our risk management policies could result in significant financial losses.

In 2010, we formed a dedicated commercial marketing group in order to capture short-term market opportunities by utilizing a portion of our storage capacity for our own account and engaging in related commercial marketing activities. Through these transactions, we seek to maintain a position that is substantially balanced between purchases on the one hand and sales or future delivery obligations on the other hand. Our general policy is (i) to purchase natural gas only in situations where we have a market for such gas, (ii) to utilize physical natural gas inventory and financial derivatives to manage and optimize seasonal and spread risks inherent in our operations and commercial management activities and to structure our transactions so that commodity price fluctuations will not have a material adverse impact on our cash flow and (iii) not to acquire or hold natural gas, futures contracts or other derivative products for the purpose of speculating on outright commodity price changes. Although we intend to conduct these transactions within these pre-defined risk parameters and we have risk management policies in place that are designed to manage and minimize commodity price and other risks, these policies will not eliminate all risks. We have in place risk management systems that are intended to quantify and manage risks, including risks related to our hedging activities such as commodity price risk and basis risk. We monitor processes and procedures to prevent unauthorized trading and to maintain substantial balance between purchases and future sales and delivery obligations. However, these steps may not detect and prevent all violations of our risk management policies and procedures, particularly if deception or other intentional misconduct is involved. There is no assurance that our risk management procedures will prevent losses that would negatively affect our business, financial condition, results of operations and ability to pay distributions to the holders of our common units and Series A subordinated units.

Table of Contents

We are subject to environmental laws and regulations that may expose us to significant costs and liabilities.

Our natural gas storage operations are subject to stringent and complex federal, state and local environmental laws and regulations. We may incur substantial costs in order to conduct our operations in compliance with these laws and regulations. These laws and regulations may impose numerous obligations that are applicable to our operations, including the acquisition of permits to conduct certain activities, increases in operating expenses or curtailment of certain operations to limit or prevent releases of materials from our facilities, the incurrence of capital expenditures associated with the installation of pollution control equipment, and the imposition of substantial liabilities for pollution resulting from our operations. Moreover, new, stricter environmental laws, regulations or enforcement policies could be implemented that significantly increase our compliance costs or the costs of any remediation of environmental contamination that may become necessary, and these costs could be material. For example, the adoption and implementation of any climate change legislation or regulations imposing reporting obligations with respect to, or limiting emissions of, greenhouse gases could result in increased operating costs and adversely affect demand for natural gas.

Numerous governmental authorities, such as the EPA and analogous state agencies, have the power to enforce compliance with these laws and regulations and the permits issued under them, oftentimes requiring difficult and costly corrective actions. Failure to comply with these laws, regulations and permits may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial obligations, and the issuance of injunctions limiting or preventing some or all of our operations. In addition, joint and several liability or strict liability may be imposed under certain environmental laws, which could cause us to become liable for the conduct of others or for consequences of our own actions that were in compliance with all applicable laws at the time those actions were taken. Private parties may also have the right to pursue legal actions to enforce compliance as well as to seek damages for non-compliance with environmental laws and regulations or for personal injury or property damage that may result from environmental and other impacts of our operations. We may not be able to recover all or any of these costs through insurance or other means, which may have a material adverse effect on our business, financial condition, results of operation and ability to make distributions. See Items 1 and 2. Business and Properties Natural Gas Regulation for more information.

If we do not complete expansion projects or make and integrate acquisitions, our future growth may be limited.

A principal focus of our strategy is to continue to grow the cash distributions on our units by expanding our business. Our ability to grow depends on our ability to complete expansion projects and make acquisitions that result in an increase in cash generated from operations on a per unit basis (i.e., are accretive). We may be unable to complete successful, accretive expansion projects or acquisitions for any of the following reasons:

- we are unable to identify attractive expansion projects or acquisition candidates that satisfy our economic and other criteria, or we are outbid for such opportunities by our competitors;
- we are unable to raise financing for such expansion projects or acquisitions on economically acceptable terms;
- we are unable to secure adequate customer commitments to use the facilities to be expanded or acquired; or
- we are unable to obtain governmental approvals or other rights, licenses or consents needed to complete such expansion projects or acquisitions.

Acquisitions or expansion projects that we complete may not perform as anticipated and could result in a reduction of our distributable cash flow on a per unit basis.

Even if we complete expansion projects or acquisitions that we believe will be accretive, such projects or acquisitions may nevertheless reduce our available cash from distributable cash flow due to the following:

- mistaken assumptions about storage capacity, deliverability, base gas needs, geological integrity, revenues, synergies, costs (including operating and general and administrative, capital, debt and equity costs), customer demand, growth potential, assumed liabilities and other factors;

an inability to complete expansion projects on schedule and within applicable budgets due to various factors, including cost overruns, schedule delays, and the inability to obtain necessary permits or approvals;

the failure to receive cash flows from an expansion project or newly acquired asset due to delays in the commencement of operations for any reason;

unforeseen operational issues or the realization of liabilities that were not known to us at the time the acquisition or expansion project was completed;

the inability to attract new customers or retain acquired customers to the extent assumed in connection with the expansion or acquisition project;

the failure to successfully integrate expansion projects or acquired assets or businesses into our operations and/or the loss of key employees; or

the impact of regulatory, environmental, political and legal uncertainties that are beyond our control.

If we consummate any future expansion projects or acquisitions, our capitalization and results of operations may change significantly, and our unitholders will not have the opportunity to evaluate the economic, financial and other relevant information that we will consider in determining the application of these funds and other resources. If any expansion projects or acquisitions we ultimately complete are not accretive to our distributable cash flow per common unit and Series A subordinated unit, our ability to make distributions may be reduced.

Our natural gas storage facilities are relatively new and have limited operating history. The facilities may not be able to deliver as anticipated, which could prevent us from meeting our contractual obligations and cause us to incur significant costs.

Although we believe that our operating gas storage facilities have been designed to meet our contractual obligations with respect to wheeling, injection, withdrawal and gas specifications, the facilities are relatively new and have a limited operating history. If we fail to wheel, inject or withdraw natural gas at contracted rates, or cannot deliver natural gas consistent with contractual quality specifications, we could incur significant costs to satisfy our contractual obligations. These costs could have an adverse impact on our business, financial condition, results of operations and ability to make distributions.

Our business involves many hazards and operational risks, some of which may not be fully covered by insurance. If a significant accident or event occurs for which we are not fully insured, our operations and financial results could be adversely affected.

Our operations are subject to all of the risks and hazards inherent in the natural gas storage business, including:

reduction of our available storage capacity at our salt caverns over time due to (i) unexpected increases in the temperature of our caverns, which reduces capacity as a result of the expansion of the stored natural gas, (ii) the long-term effect of pressure differentials between the caverns and the surrounding salt formations (known as salt creep) or (iii) problems with the structural integrity of our salt caverns;

subsidence of the geological structures where we store natural gas;

risks and hazards inherent in drilling operations associated with the development of new caverns and/or the drilling of raw water wells or salt water disposal wells;

problems maintaining the wellbores and related equipment and facilities that form a part of the infrastructure that is critical to the operation of our storage facilities;

impacts to our operations due to the unavailability of raw water for any reason or the inability to dispose of salt water through our salt water disposal wells for any reason;

damage to our storage facilities, related equipment and connecting pipelines and surrounding properties caused by hurricanes, tornadoes, floods, fires and other natural disasters or acts of terrorism;

inadvertent damage from third parties, including construction, farm and utility equipment;

leaks of natural gas and other hydrocarbons or losses of natural gas as a result of the malfunction of equipment or facilities;

collapse of storage caverns;

operator error;

Table of Contents

environmental pollution or other environmental issues, including drinking water contamination, associated with our raw water or water disposal wells or our water treatment facilities;

damage associated with equipment or material failures, pipeline or vessel ruptures or corrosion, explosions, fires and other incidents; and

other hazards that could result in personal injury and loss of life, pollution and suspension of operations.

These risks could result in substantial losses due to breaches of contractual commitments, personal injury and/or loss of life, damage to and destruction of property and equipment and pollution or other environmental damage. These risks may also result in curtailment or suspension of our operations. A natural disaster or other hazard affecting the areas in which we operate could have a material adverse effect on our operations. We are not fully insured against all risks inherent in our business. In addition, we are not insured against all environmental accidents that might occur, some of which may result in toxic tort claims. If a significant accident or event occurs for which we are not fully insured, it could result in a material adverse effect on our business, financial condition, results of operations and ability to make distributions. Furthermore, we may not be able to maintain or obtain insurance of the type and amount we desire at reasonable rates. As a result of market conditions, premiums and deductibles for certain of our insurance policies may substantially increase. In some instances, certain insurance could become unavailable or available only for reduced amounts of coverage. Additionally, we may be unable to recover from prior owners of our assets, pursuant to our indemnification rights, for potential environmental liabilities.

In addition, we share insurance coverage with PAA, for which we reimburse PAA s general partner pursuant to the terms of the omnibus agreement. To the extent PAA experiences covered losses under the insurance policies, the limit of our coverage for potential losses may be decreased.

If leakage or migration of natural gas or other hydrocarbons occurs from any of our storage facilities, our operations and financial results could be adversely affected.

Our operations are subject to the risk that natural gas or other hydrocarbons could leak or migrate from our storage facilities, causing a loss of volumes stored in the storage facilities. This risk could cause substantial losses due to our inability to deliver the stored volumes back to our customers. Furthermore, we may not be able to obtain insurance to protect against this risk, and we may not be able to maintain insurance of the type and amount we desire at reasonable rates to insure against this risk.

Restrictions in our credit facility could adversely affect our business, financial condition, results of operations, ability to make distributions to unitholders and value of our units.

Our credit agreement restricts our ability to, among other things:

make distributions of available cash to unitholders if any default or event of default (as defined in the credit agreement) exists or would result therefrom;

incur additional indebtedness;

grant or permit to exist liens or enter into certain restricted contracts;

engage in transactions with affiliates;

make any material change to the nature of our business;

- make a disposition of all or substantially all of our assets; or
- enter into a merger, consolidate, liquidate, wind up or dissolve.

Furthermore, our credit facility contains covenants requiring us to maintain certain financial ratios related to our consolidated EBITDA, consolidated interest charges and consolidated funded indebtedness, as such terms are defined in our credit agreement.

The provisions of our credit facility may affect our ability to obtain future financing and pursue attractive business opportunities and our flexibility in planning for, and reacting to, changes in business conditions. In addition, a failure to comply with the provisions

Table of Contents

of our credit facility could result in an event of default, which could enable our lenders, subject to the terms and conditions of the credit facility, to declare any outstanding principal of that debt, together with accrued interest, to be immediately due and payable. If the payment of any such debt is accelerated, our assets may be insufficient to repay such debt in full, and the holders of our units could experience a partial or total loss of their investment.

Debt we incur in the future may limit our flexibility to obtain financing and to pursue other business opportunities.

Our future level of debt could have important consequences to us, including the following:

- our ability to obtain additional financing, if necessary, for working capital, capital expenditures, acquisitions or other purposes may be impaired or such financing may not be available on favorable terms;
- our funds available for operations, future business opportunities and distributions to unitholders will be reduced by that portion of our cash flow required to make interest payments on our debt;
- we may be more vulnerable to competitive pressures or a downturn in our business or the economy generally; and
- our flexibility in responding to changing business and economic conditions may be limited.

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

For more information regarding our debt agreements, see Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources.

We are considered a subsidiary of PAA under its debt instruments and, as such, we may be directly or indirectly subject to and impacted by certain restrictions in PAA s existing and future credit facilities and indentures. These restrictions may limit our access to credit, prevent us from engaging in beneficial activities, and in certain circumstances, require us to guarantee PAA s indebtedness.

Although we are not contractually bound by and are not liable for PAA s debt under its debt instruments, we are subject to and indirectly affected by certain prohibitions and limitations contained therein. Such restrictions may prevent us from obtaining the most advantageous financing terms or from engaging in certain transactions that might otherwise be considered beneficial. For example (by reference to the most restrictive of any applicable covenant):

- We will be restricted from entering into any future sale/leaseback transactions.
- PAA is subject to a limit of 10% of PAA s consolidated net tangible assets with respect to the amount of debt that can be secured by liens on facilities owned by its subsidiaries, including us. We cannot control the incurrence of secured debt by PAA s other subsidiaries.
- We cannot give intercompany guaranties of debt for borrowed money for the benefit of PAA or any subsidiary of PAA (including any of our subsidiaries) unless we agree to guarantee PAA s outstanding debt. The same restriction would apply to a guaranty of our debt by one of our subsidiaries.

Although we believe that the restrictions in PAA s debt instruments will not have a material impact on our operations or access to credit, no assurance can be given to that effect, and PAA s ability to comply with any restrictions in PAA s debt instruments may be affected by events beyond our control.

Any debt instruments that PAA or any of its affiliates enters into in the future, including any amendments to existing credit facilities, may include additional or more restrictive limitations on our ability to conduct our business. These additional restrictions could adversely affect our ability to finance our future operations or capital needs or engage in, expand or pursue our business activities. In addition, PAA has the ability to prevent us from taking actions that would cause PAA to violate any covenants in its credit facilities or indentures, or otherwise to be in default under any of its debt instruments. In deciding whether to prevent us from taking any such action, PAA will have no fiduciary duty to us or our unitholders.

Table of Contents

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

The credit and business risk profiles of our general partner and PAA may be factors considered in credit evaluations of us. This is because our general partner, which is owned by PAA, controls our business activities, including our cash distribution policy and expansion strategy. Any adverse change in the financial condition of PAA, including the degree of its financial leverage and its dependence on cash flow from us to service its indebtedness, may adversely affect our credit and risk profile.

If we were to seek a credit rating in the future, the credit rating may be adversely affected by the leverage of our general partner or PAA, as credit rating agencies such as Standard & Poor s Ratings Services and Moody s Investors Service may consider the leverage and credit profile of PAA and its affiliates because of their ownership interest in and control of us. Any adverse effect on our credit rating would increase our cost of borrowing or hinder our ability to raise financing in the capital markets, which would impair our ability to grow our business and make distributions to unitholders.

Increases in interest rates could adversely impact our unit price, our ability to issue equity or incur debt for acquisitions or other purposes, and our ability to make cash distributions at our intended levels.

Interest rates on future credit facilities and debt offerings could be higher than current levels, causing our financing costs to increase accordingly. As with other yield-oriented securities, our unit price is impacted by the level of our cash distributions and our implied distribution yield. The distribution yield is often used by investors to compare and rank yield-oriented securities for investment decision-making purposes. Therefore, changes in interest rates, either positive or negative, may affect the yield requirements of investors who invest in our units, and a rising interest rate environment could have an adverse impact on our unit price, our ability to issue equity or incur debt for acquisitions or other purposes and to make cash distributions at our intended levels.

An impairment of goodwill could reduce our earnings.

At December 31, 2011, we had approximately $325 million of goodwill. Goodwill is recorded when the purchase price of a business exceeds the fair market value of the acquired tangible and separately measurable intangible net assets. U.S. generally accepted accounting principles, or GAAP, requires us to test goodwill for impairment on an annual basis or when events or circumstances occur indicating that goodwill might be impaired. If we were to determine that any of our goodwill was impaired, we would be required to take an immediate charge to earnings with a corresponding reduction of partners equity and increase in balance sheet leverage as measured by debt to total capitalization.

Risks Inherent in an Investment in Us

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

Pursuant to our partnership agreement, 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 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 impact the available cash that we have to distribute to our unitholders.

Cost reimbursements due to PAA s general partner 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 PAA s general partner.

Prior to making distributions on our common units, we will reimburse PAA s general partner and its affiliates for all expenses they incur on our behalf. These expenses will include all costs incurred by PAA, its general partner or our general partner in managing

32

and operating us. These operating expense reimbursements and the reimbursement of incremental general and administrative expenses we incur are not capped. In addition, PAA and our general partner will have substantial discretion in incurring third-party expenses on our behalf. Our partnership agreement provides that our general partner will determine in good faith the expenses that are allocable to us. The reimbursements to PAA s general partner and our general partner will reduce the amount of cash otherwise available for distribution to our unitholders.

Our general partner may elect to cause us to issue common units to it in connection with a resetting of the target distribution levels related to its incentive distribution rights, without the approval of the conflicts 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 Series A subordinated units outstanding and it has received incentive distributions at the highest level to which it is entitled (48.0%) 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 each target distribution level will be reset to the correspondingly higher amount that causes such reset target distribution level to exceed the reset minimum quarterly distribution by the same percentage that such distribution level exceeds the then-current minimum quarterly distribution.

If our general partner elects to reset the target distribution levels, it will be entitled to receive a number of common units and will retain its then-current general partner interest. The number of common units to be issued to our general partner will equal the 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. 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 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 our common unitholders would have otherwise received had we not issued new common units to our general partner in connection with resetting the target distribution levels.

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 our 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.

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

Under Delaware law, a unitholder could be held liable for our obligations to the same extent as a general partner if a court determined that the right of unitholders to remove our general partner or to take other action under our partnership agreement constituted participation in the control of our business.

Our general partner generally has unlimited liability for our obligations, such as our debts and environmental liabilities, except for those contractual obligations that are expressly made without recourse to our general partner. Our partnership agreement allows the general partner to incur obligations on our behalf that are expressly non-recourse to the general partner. The general partner has entered into such limited recourse obligations in most instances involving payment liability and intends to do so in the future.

In addition, Section 17-607 of the Delaware Revised Uniform Limited Partnership Act provides that under some circumstances, a unitholder may be liable to us for the amount of a distribution for a period of three years from the date of the distribution.

33

Table of Contents

Holders of our common units have limited voting rights and are not entitled to elect the directors of our general partner.

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 the directors of our general partner. The board of directors of our general partner will be chosen by PAA. 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 common units are dissatisfied, they cannot remove our general partner without its consent.

The unitholders will be unable to remove our general partner without its consent because our general partner and its affiliates own sufficient units to be able to prevent its removal. The vote of the holders of at least 66 2/3% of all outstanding units voting together as a single class is required to remove our general partner. PAA owns an aggregate of approximately 62% of our outstanding limited partner units. Also, if our general partner is removed without cause during the subordination period and units held by our general partner and its affiliates are not voted in favor of that removal, all remaining Series A subordinated units and Series B subordinated units will automatically convert into common units and any existing arrearages on our common units will be extinguished. A removal of our general partner under these circumstances would adversely affect our then-existing common units by prematurely eliminating their distribution and liquidation preference over our Series A subordinated units and Series B subordinated units, which would otherwise have continued until we had met certain distribution, performance and operational tests. Cause is narrowly defined to mean that a court of competent jurisdiction has entered a final, non-appealable judgment finding our general partner liable for actual fraud, gross negligence or willful or wanton misconduct in its capacity as our general partner. Cause does not include most cases of charges of poor management of the business, so the removal of our general partner because of the unitholder s dissatisfaction with our general partner s performance in managing our partnership will most likely result in the termination of the subordination period and conversion of all Series A subordinated units and Series B subordinated units to common units.

Our partnership agreement restricts the voting rights of 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 PAA to transfer all or a portion of its ownership interest in our general partner to a third party. The new owner of our general partner may 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 our unitholders approval, which would dilute our unitholders existing ownership interest.

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;

- because a lower percentage of total outstanding units will be Series A subordinated units, the risk that a shortfall in the payment of the minimum quarterly distribution will be borne by our common unitholders will increase;

the 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.

Table of Contents

PAA 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 February 22, 2012, PAA owned 28,214,198 common units, 11,934,351 Series A subordinated units and 13,500,000 Series B subordinated units. All of the Series A subordinated units will convert into common units at the end of the subordination period and may convert earlier under certain circumstances. The Series B subordinated units are also eligible for conversion into common units if certain operational and financial conditions are satisfied and the end of the subordination period has occurred. The sale 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 that may develop. A sale or transfer, including certain deemed transfers, by PAA of all or portions of its interests in us may cause our partnership to terminate for federal income tax purposes. For a discussion of the impact this could have on common unitholders, see Items 1A. Risk Factors Tax Risks to Common Unitholders The sale or exchange of 50% or more of our capital and profits interests during any twelve-month period will result in the termination of our partnership for federal income tax purposes.

Risks Related to Conflicts of Interest

PAA owns and controls our general partner, which has sole responsibility for conducting our business and managing our operations. PAA and our general partner have conflicts of interest and may favor PAA s interests to a unitholder s detriment.

PAA owns and controls our general partner, as well as appoints all of the officers and directors of our general partner, and some of the officers of our general partner are also officers of PAA s general partner (and one such officer is also a member of the board of directors of PAA s general partner). Although our general partner has a legal duty to manage us in a manner that is beneficial to us and our unitholders, the directors and officers of our general partner have a legal duty to manage our general partner in a manner that is beneficial to its owner, PAA. Conflicts of interest may arise between PAA and 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 PAA over our interests and the interests of our unitholders.

PAA may engage in competition with us.

Although PAA has stated that it intends to utilize our partnership as the primary vehicle through which it will participate in the natural gas storage business, PAA and its affiliates are not limited in their ability to compete with us.

Our partnership agreement defines and modifies the duties of our general partner and restricts the remedies available to holders of our common and subordinated units for actions taken by our general partner.

Our partnership agreement contains provisions that define the standard of care that our general partner must exercise and restrict the remedies available to unitholders for actions taken by our general partner in accordance with that standard of care, including in circumstances that might otherwise be challenged under state law standards. For example, our partnership agreement:

permits our general partner to make a number of decisions in its individual capacity, as opposed to in its capacity as our general partner. This entitles our general partner to consider only the interests and factors that it desires, and it has no duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or any limited partner. Examples of decisions that our general partner may make in its individual capacity include:

(a) how to allocate corporate opportunities among us and our general partner s affiliates;

(b) whether to exercise its limited call right;

(c) how to exercise its voting rights with respect to the units it owns;

(d) whether to exercise its registration rights;

(e) whether to elect to reset target distribution levels; and

(f) whether or not to consent to any merger or consolidation of the partnership or amendment to the partnership agreement.

provides that whenever our general partner makes a determination, including any determination with respect to distributable cash flow or any components thereof, or takes, or declines to take, any other action in its capacity as our general partner, our general partner is required to make such determination, or take or decline to take such other action, in good faith, and will not be subject to any other or different standard imposed by our partnership agreement, Delaware law, or any other law, rule or regulation, or at equity;

provides that our general partner will not have any liability to us or our unitholders for decisions made in its capacity as a general partner so long as such decisions are made in good faith, meaning that it subjectively believed that the decision was (i) with respect to matters involving us, in, or not opposed to, the best interests of our partnership and (ii) with respect to matters involving the relative rights and privileges of holders of our equity interests, consistent with the intent of the provisions of our partnership agreement;

provides that our general partner and its officers and directors will not be liable for monetary damages to us, our limited partners or their assignees resulting from any act or omission unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that our general partner or its officers and directors, as the case may be, acted in bad faith or engaged in fraud or willful misconduct or, in the case of a criminal matter, acted with knowledge that the conduct was criminal;

generally provides that any resolution or course of action adopted by our general partner and its affiliates in respect of a conflict of interest will be permitted and deemed approved by all of our partners, and will not constitute a breach of our partnership agreement or any duty stated or implied by law or equity if the resolution or course of action in respect of such conflict of interest is:

(a) approved by the conflicts committee of our general partner after due inquiry, based on a subjective belief that the course of action or determination that is the subject of such approval is fair and reasonable to us;

(b) approved by the vote of a majority of the outstanding common units, excluding any common units owned by our general partner and its affiliates, directors and executive officers;

(c) determined by our general partner (after due inquiry) to be on terms no less favorable to us than those generally being provided to or available from unrelated third parties; or

(d) approved by our general partner (after due inquiry) based on a subjective belief that the course of action or determination that is the subject of such approval is fair and reasonable to us, which may include taking into account the totality of the circumstances and relationships involved (our short-term or long-term interests and other arrangements or relationships that could be considered favorable or advantageous to us); and

provides that, to the fullest extent permitted by law, in connection with any action or inaction of, or determination made by, our general partner s board of directors or its conflicts committee with respect to any matter relating to us, it shall be presumed that our general partner s board of directors or its conflicts committee acted in a manner that satisfied the contractual standards set forth in our partnership agreement, and in any proceeding brought by any limited partner or by or on behalf of such limited partner or any other limited partner or our partnership challenging any such action or inaction of, or determination made by, our general partner, the person bringing or prosecuting such proceeding shall have the burden of overcoming such presumption.

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

Our general partner intends to 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 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 would reduce the amount of cash otherwise available for distribution to our unitholders.

36

Our general partner has a limited call right that may require 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, unitholders may be required to sell their common units at an undesirable time or price and may not receive any return on their investment. Unitholders may also incur a tax liability upon a sale of their units.

Tax Risks to Common Unitholders

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

The anticipated after-tax economic benefit of an investment in our common units depends largely on our being treated as a partnership for federal income tax purposes. A publicly traded partnership such as us may be treated as a corporation for federal income tax purposes unless it satisfies a qualifying income requirement. Based on our current operations we believe that we are treated as a partnership rather than a corporation for such purposes; however, a change in our business could cause us to be treated as a corporation for federal income tax purposes. We have not requested, and do not plan to request, a ruling from the Internal Revenue Service, or the IRS, on this or any other tax matter affecting us.

In addition, a change in current law may cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to entity-level taxation. In addition, because of widespread state budget deficits and other reasons, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. Specifically, we will be subject to an entity-level tax on any portion of our income that is generated in Texas in the prior year. Imposition of any such additional taxes on us will reduce the cash available for distribution to our unitholders. Our partnership agreement provides that if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for federal income tax purposes, our target distribution amounts will be adjusted to reflect the impact of that law on 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%, and would likely pay state income tax at varying rates. Distributions to our unitholders would generally be taxed again as corporate distributions, and no income, gains, losses, deductions or credits would flow through to them. Because a tax would be imposed upon us as a corporation, our cash available for distribution to our unitholders would be substantially reduced. Therefore, treatment of us as a corporation would 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.

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

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

The present U.S. federal income tax treatment of (i) publicly traded partnerships, including us, or (ii) an investment in our common units may be modified by administrative, legislative or judicial interpretation at any time. For example, members of Congress have recently considered substantive changes to the existing federal income tax laws that affect publicly traded partnerships. Any modification to the U.S. federal income tax laws and interpretations thereof may or may not be applied retroactively and could make it more difficult or impossible to meet the exception for certain publicly traded partnerships to be treated as partnerships for U.S. federal income tax purposes. Although the considered legislation would not appear to have affected our treatment as a partnership, we are unable to predict whether any of these changes or other proposals will be reintroduced or will ultimately be enacted. Any such changes could negatively impact the value of an investment in our common units.

Our 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 that could be different in amount than the cash we distribute, they will be required to pay any federal income taxes and, in some cases, state and local income taxes on their share of our taxable income whether or not they receive cash distributions from us. Our unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax liability that results from that income.

Table of Contents

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

We will be considered to have technically terminated our partnership for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. PAA owns more than 50% of the total interests in our capital and profits interests. Therefore, a transfer by PAA of all or a portion of its interests in us, including a deemed transfer as a result of a termination of PAA s partnership for federal income tax purposes, could result in a termination of our partnership for federal income tax purposes. 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. In the case of a unitholder reporting on a taxable year other than a fiscal year ending December 31, the closing of our taxable year may also result in more than twelve months of our taxable income or loss being includable in his taxable income for the year of termination. Our termination currently would not affect our classification as a partnership for federal income tax purposes, but instead, we would be treated as a new partnership for tax purposes. If treated as a new partnership, we must make new tax elections and could be subject to penalties if we are unable to determine that a termination occurred. The IRS has recently announced a relief procedure whereby if a publicly traded partnership that has technically terminated requests and the IRS grants special relief, among other things, the partnership may be permitted to provide only a single Schedule K-1 to unitholders for the tax years in which the termination occurs.

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

If our unitholders sell their common units, they will recognize a gain or loss equal to the difference between the amount realized and their tax basis in those common units. Because distributions in excess of a unitholder s allocable share of our net taxable income decrease the unitholder s tax basis in their common units, the amount, if any, of such prior excess distributions with respect to the units they sell will, in effect, become taxable income to the unitholder if they sell such units at a price greater than their tax basis in those units, even if the price the unitholder receives is less than their original cost. Furthermore, a substantial portion of the amount realized, whether or not representing gain, may be taxed as ordinary income due to potential recapture items, including depreciation recapture. In addition, because the amount realized includes a unitholder s share of our nonrecourse liabilities, if a unitholder sells units, the unitholder may incur a tax liability in excess of the amount of cash they receive from the sale.

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

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

If the IRS contests the federal income tax positions we take, the market for our common units may be adversely impacted and the cost of any IRS contest will reduce our cash available for distribution or debt service.

The IRS may adopt positions that differ from the positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we take. A court may not agree with some or all of the positions we take. Any contest with the IRS may materially and adversely impact the market for our common units and the price at which they trade. Our costs of any contest with the IRS will be borne indirectly by our unitholders and our general partner because the costs will reduce our cash available for distribution or debt service.

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

To maintain the uniformity of the economic and tax characteristics of common units, we have adopted depreciation and amortization positions that may not conform to all aspects of existing Treasury Regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to our unitholders. It also could affect the timing of these tax benefits or the amount of gain from the sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to our unitholders tax returns.

Table of Contents

We have adopted certain valuation methodologies that may result in a shift of income, gain, loss and deduction between our 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 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 our general partner, which may be unfavorable to such unitholders. Moreover, under our valuation methods, 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 valuation 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 our 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.

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

A unitholder whose 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, he 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 there is no tax concept of loaning a partnership interest, 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 the loaned units. In that case, he may no longer be treated for tax purposes 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 should modify any applicable brokerage account agreements to prohibit their brokers from borrowing their common units.

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

In addition to federal income taxes, our unitholders will likely be subject to other taxes, including state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we conduct business or own property, even if our unitholders do not live in any of those jurisdictions. Our 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, our unitholders may be subject to penalties for failure to comply with those requirements. We currently own assets and conduct business in the states of Louisiana, Michigan and Mississippi. Each of these states currently imposes a personal income tax and also imposes income taxes on corporations and other entities. As we make acquisitions or expand our business, we may own assets or conduct business in additional states or foreign jurisdictions that impose a personal income tax. It is a unitholder s responsibility to file all U.S. federal, foreign, state and local tax returns.

Item 1B. ***Unresolved Staff Comments***

None.

Item 3. ***Legal Proceedings***

In early December 2011, Pine Prairie received a property tax bill from Evangeline Parish, Louisiana for approximately $1.4 million that assessed taxes on property that Pine Prairie maintains is clearly exempt from tax pursuant to a 2006 tax abatement arrangement. In order to properly protest such tax assessment under Louisiana law, Pine Prairie was required to pay the disputed taxes by December 31, 2011 and file suit within 30 days thereafter. Pine Prairie paid the taxes under protest on December 29, 2011 and filed suit within the required 30 day period seeking recovery of the taxes based on the tax abatement arrangement. Pending resolution of the dispute, the taxes paid under protest are required to be held in a segregated account by Evangeline Parish and will be returned to Pine Prairie with interest when and if Pine Prairie prevails in the lawsuit. Except for such matter, we are not a party to any legal proceeding other than legal proceedings arising in the ordinary course of our business. We are also a party to various administrative and regulatory proceedings that have arisen in the ordinary course of our business, none of which we believe to be material.

Item 4. ***Mine Safety Disclosures***

Not applicable.

Table of Contents

PART II

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

Our common units are listed and traded on the New York Stock Exchange (NYSE) under the symbol PNG. As of February 22, 2012, the closing market price for our common units was $18.96 per unit and there were approximately 53,193,825 common units outstanding. As of December 31, 2010, there were approximately 10,200 record holders and beneficial owners (held in street name).

The following table sets forth high and low sales prices for our common units and the cash distributions declared per common unit for the periods indicated:

	Common Unit Price Range		Cash Distributions [(1)]
2011	**High**	**Low**	
4th Quarter	$ 18.99	$ 15.51	$ 0.3575
3rd Quarter	$ 23.72	$ 15.91	$ 0.3575
2nd Quarter	$ 24.92	$ 20.75	$ 0.3450
1st Quarter	$ 25.50	$ 22.73	$ 0.3450
2010			
4th Quarter	$ 25.75	$ 22.61	$ 0.3450
3rd Quarter	$ 26.65	$ 22.61	$ 0.3375
2nd Quarter [(2)]	$ 26.00	$ 22.25	$ 0.2114
1st Quarter [(3)]	$	$	$

(1) Cash distributions for a quarter are declared and paid in the following calendar quarter. See Cash Distribution Policy below for a discussion of our policy regarding distribution payments.

(2) The distribution paid for the second quarter of 2010 represents our minimum quarterly distribution prorated for the period from May 5, 2010 (the date of closing of our initial public offering) through June 30, 2010.

(3) Our common units did not commence trading on the NYSE until April 2010.

Our common units are used as a form of compensation to our directors and our employees. Additional information regarding our equity compensation plans is included in Part III of this report under Item 13. Certain Relationships and Related Transactions, and Director Independence.

Cash Distribution Policy

We will distribute all of our available cash to our unitholders, of record on the applicable record date, within 45 days following the end of each quarter in the manner described below. Available cash generally means, for any quarter ending prior to liquidation, all cash on hand at the end of that quarter less the amount of cash reserves that are necessary or appropriate in the reasonable discretion of the general partner to:

- provide for the proper conduct of our business;
- comply with applicable law or any partnership debt instrument or other agreement; or
- provide funds for distributions to unitholders and the general partner in respect of any one or more of the next four quarters.

We distribute all of our available cash each quarter in the following manner:

first, 98.0% to the holders of common units and 2.0% to our general partner, until each common unit has received the minimum quarterly distribution of $0.3375, plus any arrearages from prior quarters; and

second, 98.0% to the holders of Series A subordinated units and 2.0% to our general partner, until each Series A subordinated unit has received the minimum quarterly distribution of $0.3375.

Table of Contents

If cash distributions to our unitholders exceed $0.3375 per common unit and Series A subordinated unit in any quarter, our general partner will receive, in addition to distributions on its 2.0% general partner interest, incentive distributions in increasing percentages, up to 48.0%, of the cash we distribute in excess of that amount as follows:

	Total Quarterly Distributions per Common Unit and Series A Subordinated Unit	Marginal Percentage Interest in Distributions	
		Unitholders	General Partner
Minimum quarterly distribution	$0.3375	98.0%	2.0%
First Target distribution	above $0.3375 up to $0.37125	85.0%	15.0%
Second Target distribution	above $0.37125 up to $0.50625	75.0%	25.0%
Thereafter	above $0.50625	50.0%	50.0%

Our general partner has the right, at any time when there are no Series A subordinated units outstanding and it has received incentive distributions at the highest level to which it is entitled (48.0%) for each of the prior four consecutive fiscal quarters, to reset the initial target distribution levels at higher levels based on our cash distributions at the time of the exercise of the reset election.

The following table details the distributions subsequent to our initial public offering (in millions, except per unit amounts):

		Distributions Paid					
		Common	Series A Subordinated	General Partner			Distributions per limited partner
Date Declared	Date Paid or To Be Paid	Units	Units	Incentive	2%	Total	unit
January 12, 2012 (1)	February 14, 2012	$ 21.2	$ 4.3	$ 0.2	$ 0.5	$ 26.2	$ 0.3575
October 11, 2011	November 14, 2011	$ 21.2	$ 4.3	$ 0.2	$ 0.5	$ 26.2	$ 0.3575
July 11, 2011	August 12, 2011	$ 20.4	$ 4.1	$ 0.1	$ 0.5	$ 25.1	$ 0.3450
April 11, 2011	May 13, 2011	$ 20.4	$ 4.1	$ 0.1	$ 0.5	$ 25.1	$ 0.3450
January 12, 2011	February 14, 2011	$ 10.9	$ 4.1	$ 0.1	$ 0.3	$ 15.4	$ 0.3450
October 12, 2010	November 12, 2010	$ 10.7	$ 4.0	$	$ 0.3	$ 15.0	$ 0.3375
July 13, 2010	August 13, 2010 (2)	$ 6.7	$ 2.9	$	$ 0.2	$ 9.8	$ 0.2114

(1) Payable to unitholders of record on February 3, 2012, for the period October 1, 2011 through December 31, 2011.

(2) Amount represents a quarterly distribution of $0.3375 per unit prorated from the May 5, 2010 closing date of the IPO through June 30, 2010.

We do not have a legal obligation to pay the minimum quarterly distribution or any other distribution except to distribute available cash as provided in our partnership agreement. Our cash distribution policy may be changed at any time and is subject to certain restrictions, including our partnership agreement, our credit facility or other debt agreements and applicable partnership law. Under the terms of the agreements governing our debt, we are prohibited from declaring or making any distribution to unitholders if a default or event of default (as defined in such agreements) exists. No such default has occurred. See Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources.

See Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters for information regarding securities authorized for issuance under equity compensation plans.

Issuer Purchases of Equity Securities

We did not repurchase any of our common units during the fourth quarter of fiscal 2011, and we do not have any announced or existing plans to repurchase any of our common units.

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

The historical financial information below was derived from our audited consolidated financial statements, or those of our predecessor as further discussed below, as of December 31, 2011, 2010, 2009, 2008 and 2007 and for the years ended December 31, 2011 and 2010, the period from September 3, 2009 through December 31, 2009, the period from January 1, 2009 through September 2, 2009 and the years ended December 31, 2008 and 2007. Pro forma information for the year ended December 31, 2009 is unaudited. As a result of the push-down accounting requirements applied in conjunction with the PAA Ownership Transaction (see Note 1 to our consolidated financial statements), the financial information of PNG for periods preceding (designated as Predecessor) and succeeding (designated as Successor) the PAA Ownership Transaction have been prepared under two different cost bases of accounting. A vertical line separates financial information for periods preceding and succeeding the PAA Ownership Transaction to highlight the fact that such information was prepared under different bases of accounting. The selected financial data should be read in conjunction with the Consolidated Financial Statements, including the notes thereto, and Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations.

	Predecessor			Successor	Pro Forma [1]	Successor	Successor
	Year Ended December 31, 2007	Year Ended December 31, 2008	January 1, 2009 through September 2, 2009	September 3, 2009 through December 31, 2009	Year Ended December 31, 2009 (Unaudited)	Year Ended December 31, 2010	Year Ended December 31, 2011
	(in thousands, except for per unit, working storage capacity and monthly operating metrics)						
Statement of operations data:							
Total revenues	$ 36,945	$ 49,177	$ 46,929	$ 25,251	$ 72,180	$ 100,287	$ 342,964
Storage related costs and natural gas sales	3,847	8,934	8,792	7,003	15,795	23,465	205,092
Operating costs (except those shown below)	3,947	4,059	4,820	3,257	8,077	7,242	11,621
Fuel expense	1,140	2,320	1,816	578	2,394	2,368	4,924
General and administrative expenses	3,755	3,874	3,562	4,083	8,885	15,965	22,566
Depreciation, depletion and amortization	4,520	6,245	8,054	3,578	11,341	14,119	33,714
Total costs and expenses	17,209	25,432	27,044	18,499	46,492	63,159	277,917
Operating income	19,736	23,745	19,885	6,752	25,688	37,128	65,047
Interest expense	(7,108)	(4,941)	(4,352)	(4,262)	(11,676)	(7,323)	(5,354)
Other income / (expense)	5,378	1,669	458	(2)	456	(18)	5
Income tax expense		(887)	(473)		(473)		
Net income	$ 18,006	$ 19,586	$ 15,518	$ 2,488	$ 13,995	$ 29,787	$ 59,698
Calculation of Limited Partner Interest in Net Income: [2]							
Net income	n/a	n/a	n/a	n/a	n/a	$ 24,359	$ 59,698
Less general partner interest in net income	n/a	n/a	n/a	n/a	n/a	537	1,793
Limited partner interest in net income	n/a	n/a	n/a	n/a	n/a	$ 23,822	$ 57,905
Per unit data:							
Basic net income per limited partner unit [2]	n/a	n/a	n/a	n/a	n/a	$ 0.54	$ 0.85
Diluted net income per limited partner unit [2]	n/a	n/a	n/a	n/a	n/a	$ 0.54	$ 0.85
Declared distribution per limited partner unit [3]	n/a	n/a	n/a	n/a	n/a	$ 0.89	$ 1.41
Balance sheet data (at end of period):							
Total assets	$ 674,765	$ 811,436		$ 900,407		$ 998,728	$ 1,849,999
Long-term debt [4]	$ 352,713	$ 415,263		$ 450,523		$ 259,900	$ 453,508
Total debt	$ 355,163	$ 417,713		$ 450,523		$ 259,900	$ 521,500
Members /partners capital	$ 294,717	$ 363,229		$ 432,744		$ 723,390	$ 1,285,626
Other financial data:							
Adjusted EBITDA [5][6]	$ 29,663	$ 31,001	$ 28,701	$ 12,165	$ 39,626	$ 53,857	$ 107,229
Distributable cash flow [5]	$ 22,156	$ 25,577	$ 23,965	$ 7,200	$ 26,863	$ 44,962	$ 99,914
Maintenance capital expenditures		$ 377	$ 384	$ 320	$ 704	$ 438	$ 798
Net cash provided by (used in) operating activities	$ 22,343	$ 21,818	$ 22,603	$ 15,265		$ 44,361	43,894
Net cash provided by (used in) investing activities	$ (177,280)	$ (118,890)	$ (58,561)	$ (9,656)		$ (103,580)	$ (810,274)
Net cash provided by (used in) financing activities	$ 145,743	$ 122,344	$ 23,636	$ (22,813)		$ 56,441	$ 766,530
Operating data:							
Net revenue margin [7]	$ 33,098	$ 40,243	$ 38,137	$ 18,248	$ 56,385	$ 76,452	$ 137,734
Other operating expenses / G&A / Other	(3,435)	(9,242)	(9,436)	(6,083)	(16,759)	(22,595)	(30,505)

Adjusted EBITDA	$ 29,663	$ 31,001	$ 28,701	$ 12,165	$ 39,626	$ 53,857	$ 107,229
Average working storage capacity (Bcf) [8]	26	27	36	40	38	47	71
Monthly Operating Metrics ($/Mcf)							
Net revenue margin	$ 0.11	$ 0.12	$ 0.13	$ 0.11	$ 0.12	$ 0.14	$ 0.16
Operating expenses / G&A / Other	(0.01)	(0.03)	(0.03)	(0.03)	(0.03)	(0.04)	(0.04)
Adjusted EBITDA	$ 0.10	$ 0.09	$ 0.10	$ 0.08	$ 0.09	$ 0.10	$ 0.12

(1) In September 2009, Plains All American Pipeline, L.P. became the sole owner of a predecessor of PNG by acquiring an additional 50% interest in that predecessor. Application of push-down accounting in conjunction with this transaction resulted in financial information for periods prior to and subsequent to this transaction being prepared under a different basis of accounting. For comparison purposes, the pro-forma presentation places the 2009 period on the same basis of accounting as the most recent period. The following items were impacted by the adjustment: General and administrative expenses, Depreciation, depletion, and amortization, and Interest expense. The net impact of the pro-forma adjustments was a $4.0 million decrease to Net income and Adjusted Net Income and a $1.2 million decrease in EBITDA and Adjusted EBITDA for the year ended December 31, 2009. These pro-forma adjustments are not attributable to the Partnership s May 2010 initial public offering. For further discussion, see Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations.

Table of Contents

(2) Reflective of general and limited partner interest in net income since closing of the Partnership s initial public offering. See Note 4 to our consolidated financial statements.

(3) Amount represents distributions per limited partner unit attributable to the fiscal period. Cash distributions for a fiscal quarter are declared and paid in the following calendar quarter. No distributions were declared for any periods prior to May 5, 2010, the closing of our initial public offering. Our series B subordinated units were not entitled to receive distributions for any of the periods presented. See Note 6 to our consolidated financial statements.

(4) Excludes approximately $68.0 million of borrowings under our $450 million five-year senior unsecured credit agreement as of December 31, 2011. Such borrowings, which are related to a portion of our funded hedged natural gas inventory, have been designated as working capital borrowings and must be repaid within one year. See Note 5 to our consolidated financial statements.

(5) For further discussion, please read, Non-GAAP and Segment Financial Measures.

(6) The period from September 3, 2009 through December 31, 2009 includes total expenses of approximately $1 million associated with increased personnel costs, including added staffing, and accelerated audit and other costs related to our increased acquisition activities and our efforts to become a publicly traded entity as well as increased overhead allocations from PAA.

(7) Net revenue margin equals total revenues less storage related costs, natural gas sales costs and mark-to-market of open derivative positions.

(8) Calculated as the sum of total owned working gas storage capacity at the end of each month divided by the number of months in the period.

Non-GAAP and Segment Financial Measures

To supplement our financial information presented in accordance with GAAP, management uses Adjusted EBITDA and distributable cash flow in its evaluation of past performance and prospects for the future. Management believes that the presentation of such additional financial measures provides useful information to investors regarding our financial condition and results of operations because these measures, when used in conjunction with related GAAP financial measures, (i) provide additional information about our core operations and ability to generate and distribute cash flow, (ii) provide investors with the financial analytical framework upon which management bases financial, operational, compensation and planning decisions and (iii) present measurements that investors, rating agencies and debt holders have indicated are useful in assessing us and our results of operations. Adjusted EBITDA and/or distributable cash flow may exclude, for example, the impact of unique and infrequent items, items outside of management s control and/or items that are not indicative of our core operating results and business outlook, which we have defined hereinafter as selected items impacting comparability. These additional financial measures are reconciled to net income, the most directly comparable measures as reported in accordance with GAAP, in the following table and should be viewed in addition to, and not in lieu of, our consolidated financial statements and footnotes.

We define Adjusted EBITDA as earnings before interest expense, taxes, depreciation, depletion and amortization, equity compensation plan charges, gains and losses from derivative activities and applicable selected items impacting comparability.

Distributable cash flow, as determined by our general partner, is defined as: (i) net income; plus or minus, as applicable, (ii) any amounts necessary to offset the impact of any items included in net income that do not impact the amount of available cash; plus (iii) any acquisition-related expenses deducted from net income and associated with (a) successful acquisitions or (b) any other potential acquisitions that have not been abandoned; minus (iv) any acquisition related expenses covered by clause (iii)(b) immediately preceding that relate to (a) potential acquisitions that have since been abandoned or (b) potential acquisitions that have not been consummated within one year following the date such expense was incurred (except that if the potential acquisition is the subject of a pending purchase and sale agreement as of such one-year date, such one-year period of time shall be extended until the first to occur of the termination of such purchase and sale agreement or the first day following the closing of the acquisition contemplated by such purchase and sale agreement); and minus (v) maintenance capital expenditures. The types of items covered by clause (ii) above include (a) depreciation, depletion and amortization expense, (b) any gain or loss from the sale of assets not in the ordinary course of business, (c) any gain or loss as a result of a change in accounting principle, (d) any non-cash gains or items of income and any non-cash losses or expenses, including asset impairments, amortization of debt discounts, premiums or issue costs, mark-to-market activity associated with hedging and with non-cash revaluation and/or fair valuation of assets or liabilities and (e) earnings or losses from unconsolidated subsidiaries except to the extent of actual cash distributions received. Distributable cash flow does not reflect actual cash on hand that is available for distribution to our unitholders.

Table of Contents

The following table reconciles Non-GAAP and segment financial measures to the most directly comparable measures as reported in accordance with GAAP (in thousands):

		Predecessor		Successor	Pro Forma [1]	Successor	Successor
	Year Ended December 31, 2007	Year Ended December 31, 2008	January 1 - September 2, 2009	September 3 - December 31, 2009	Year Ended December 31, 2009	Year Ended December 31, 2010	Year Ended December 31, 2011
Adjusted EBITDA reconciliation							
Net income	$ 18,006	$ 19,586	$ 15,518	$ 2,488	$ 13,995	$ 29,787	$ 59,698
Income tax expense		887	473		473		
Interest expense, net of amounts capitalized	7,108	4,941	4,352	4,262	11,676	7,323	5,354
Depreciation, depletion and amortization	4,520	6,245	8,054	3,578	11,341	14,119	33,714
Selected items impacting Adjusted EBITDA							
Equity compensation expense	553	(110)	304	1,467	1,771	2,747	4,046
Acquisition related costs						251	4,055
Insurance deductible related to property damage incident							500
Mark-to-market on open derivative positions	(524)	(548)		370	370	(370)	(138)
Adjusted EBITDA	**$ 29,663**	**$ 31,001**	**$ 28,701**	**$ 12,165**	**$ 39,626**	**$ 53,857**	**$ 107,229**
Distributable cash flow reconciliation							
Net income	$ 18,006	$ 19,586	$ 15,518	$ 2,488	$ 13,995	$ 29,787	$ 59,698
Depreciation, depletion and amortization	4,520	6,245	8,054	3,578	11,341	14,119	33,714
Income tax expense		887	473		473		
Acquisition related costs						251	4,055
Maintenance capital expenditures		(377)	(384)	(320)	(704)	(438)	(798)
Other non cash items:							
Equity compensation expense, net of cash payments	154	(216)	304	1,084	1,388	1,613	3,383
Mark-to-market on open derivative positions	(524)	(548)		370	370	(370)	(138)
Distributable cash flow	**$ 22,156**	**$ 25,577**	**$ 23,965**	**$ 7,200**	**$ 26,863**	**$ 44,962**	**$ 99,914**

(1) In September 2009, Plains All American Pipeline, L.P. became the sole owner of a predecessor of PNG by acquiring an additional 50% interest in that predecessor. Application of push-down accounting in conjunction with this transaction resulted in financial information for periods prior to and subsequent to this transaction being prepared under a different basis of accounting. For comparison purposes, the pro-forma presentation places the 2009 period on the same basis of accounting as the most recent period. The following items were impacted by the adjustment: General and administrative expenses, Depreciation, depletion and amortization, and Interest expense. The net impact of the pro-forma adjustments was a $4.0 million decrease to Net income and Adjusted Net Income and a $1.2 million decrease in EBITDA and Adjusted EBITDA for the year ended December 31, 2009. These pro-forma adjustments are not attributable to the Partnership s May 2010 initial public offering.

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

Introduction

The following discussion is intended to provide investors with an understanding of our financial condition and results of our operations, including periods prior to our initial public offering on May 5, 2010. Such analysis should be read in conjunction with the historical audited consolidated financial statements, and accompanying notes. For ease of reference, we refer to the historical financial results of PAA Natural Gas Storage, LLC (PNGS) prior to our initial public offering as being our historical financial results. Unless the context otherwise requires, references to we, us, our, and the Partnership are intended to mean the business and operations of PAA Natural Gas Storage, L.P. (the Partnership or PNG) and its consolidated subsidiaries since May 5, 2010. When used in the historical context (i.e. prior to May 5, 2010), these terms are intended to mean the business and operations of PNGS. Unless the context indicates otherwise, for purposes of the following discussion PAA refers to Plains All American Pipeline, L.P. (the owner of our general partner) (NYSE: PAA) and its consolidated subsidiaries and affiliates other than the Partnership and its general partner and their respective subsidiaries.

Table of Contents

For periods prior to our initial public offering, the historical consolidated financial statements are those of PNGS, our predecessor. Through the contribution of all of the equity interest of PNGS to us in connection with the closing of our initial public offering on May 5, 2010, all of the assets, liabilities and operations of PNGS were contributed directly or indirectly by PAA to the Partnership. For further discussion regarding the Partnership s initial public offering, please see Notes 1 and 6 to our consolidated financial statements.

As further discussed in Note 1 to our consolidated financial statements, PNGS became a wholly owned subsidiary of PAA on September 3, 2009 when PAA acquired an additional 50.0% interest in PNGS from Vulcan Capital (the PAA Ownership Transaction). Application of push-down accounting from PAA to PNGS resulted in a change in carrying value for certain assets and liabilities of PNGS.

Our discussion and analysis includes the following:

- Executive Summary
  - Company Overview
  - Overview of Operating Results, Capital Investments and Significant Activities
- Critical Accounting Policies and Estimates
- Recent Accounting Pronouncements
- Results of Operations
- Outlook
- Liquidity and Capital Resources

Executive Summary

Company Overview

We are a fee-based, growth-oriented Delaware limited partnership formed by Plains All American in January 2010 to own, operate and grow the natural gas storage business that PAA acquired in 2005 and has continuously operated since that time. In conjunction with our initial public offering in May 2010, PAA contributed the equity interest in the entities that owned its natural gas storage business to us. Our business consists of the acquisition, development, operation and commercial management of natural gas storage facilities.

As of December 31, 2011, we owned and operated three natural gas storage facilities located in Louisiana, Mississippi and Michigan that have an aggregate working gas storage capacity of approximately 76 Bcf and an aggregate peak injection and withdrawal capacity of 4.1 Bcf per day and 6.4 Bcf per day, respectively. Our Pine Prairie and Southern Pines facilities are recently constructed, high-deliverability salt cavern natural gas storage complexes located in Evangeline Parish, Louisiana and Greene County, Mississippi, respectively. Our Bluewater facility is a depleted reservoir natural gas storage complex located approximately 50 miles from Detroit in St. Clair County, Michigan. As of December 31, 2011, through these facilities, PNG had a total of seven operational salt storage caverns and two depleted reservoirs used for natural gas storage. Additionally, our dedicated commercial marketing group captures short-term market opportunities by utilizing a portion of our storage capacity for our own account and engaging in related commercial marketing activities.

Overview of Operating Results, Capital Investments and Significant Activities

Adjusted EBITDA for the year ended December 31, 2011 was $107.2 million, a 99% increase over Adjusted EBITDA of $53.9 million for the year ended December 31, 2010. This increase was primarily the result of the completion of the Southern Pines Acquisition on February 9, 2011, results of PNG Marketing, LLC (our commercial optimization company) and incremental revenues attributable to expansion of our Pine Prairie facility, including placing our fourth cavern into service during 2011, which provided an additional 10 Bcf of working gas capacity. See Results of Operations for further discussion and analysis of our operating results. Excluding acquisitions, expansion capital expenditures for 2011 were approximately $88.5 million. Such expenditures were principally associated with the ongoing development of our Pine Prairie and Southern Pines facilities.

Table of Contents

In February 2011, we completed the acquisition of SG Resources Mississippi, LLC (SG Resources) from SGR Holdings, L.L.C. for consideration of approximately $765 million (approximately $750 million, net of cash and other working capital acquired). The primary asset of SG Resources was the Southern Pines Energy Center (Southern Pines), a FERC-regulated, salt-cavern natural gas storage facility located in Greene County, Mississippi.

In August 2011, we entered into a new $450 million five-year senior unsecured credit agreement, which replaced our $400 million, three year senior unsecured revolving credit facility that was scheduled to mature in May 2013.

Critical Accounting Policies and Estimates

Critical Accounting Policies

We have adopted various accounting policies to prepare our consolidated financial statements in accordance with GAAP. These critical accounting policies are discussed in Note 2 to our consolidated financial statements.

Critical Accounting Estimates

The preparation of financial statements in conformity with GAAP requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities, as well as the disclosure of contingent assets and liabilities, at the date of the financial statements. Such estimates and assumptions may also affect the reported amounts of revenues and expenses during the reporting period. Although we believe these estimates are reasonable, actual results could differ from these estimates. The critical accounting estimates that we have identified are discussed below.

Fair Value of Assets and Liabilities Acquired and Identification of Associated Goodwill and Intangible Assets. In accordance with FASB guidance regarding business combinations, with each acquisition, we allocate the cost of the acquired entity to the assets and liabilities assumed based on their estimated fair values at the date of acquisition. If the initial accounting for the business combination is incomplete when the combination occurs, an estimate will be recognized. Any subsequent adjustment to this estimate, if material, will be adjusted as if the amount was recognized when the combination occurred. We also expense the transaction costs as incurred in connection with each acquisition. In addition, we are required to recognize intangible assets separately from goodwill. Intangible assets with finite lives are amortized over their estimated useful lives as determined by management. Goodwill and intangible assets with indefinite lives are not amortized but instead are periodically assessed for impairment.

Impairment testing entails estimating future net cash flows relating to the asset, based on management s estimate of market conditions including pricing, demand, competition, operating costs and other factors. Determining the fair value of assets and liabilities acquired, as well as intangible assets that relate to such items as customer relationships, contracts, and industry expertise involves professional judgment and is ultimately based on acquisition models and management s assessment of the value of the assets acquired and, to the extent available, third-party assessments. Uncertainties associated with these estimates include assumptions regarding natural gas supply and demand, volatility and pricing of natural gas, economic obsolescence factors in the area and potential future sources of cash flow. Although the resolution of these uncertainties has not historically had a material impact on our results of operations or financial condition, we cannot provide assurance that actual amounts will not vary significantly from estimated amounts. We perform our goodwill impairment test annually (as of June 30) and when events or changes in circumstances indicate that the carrying value may not be recoverable. We did not have any goodwill impairments in 2011, 2010 or 2009.

Property and Equipment and Depreciation Expense. We compute depreciation using the straight-line method based on estimated useful lives. We periodically evaluate the estimated useful lives of our property and equipment and most recently revised our estimates in September 2009. See Note 15 to our consolidated financial statements.

We also evaluate our property and equipment for impairment when events or circumstances indicate that the carrying value of these assets may not be recoverable. The impairment evaluation is highly dependent on the underlying assumptions of related cash flows. We consider the fair value estimate used to calculate impairment of property and equipment a critical accounting estimate. In determining the existence of an impairment in carrying value, we make a number of subjective assumptions as to:

- whether there is an indication of impairment;

the grouping of assets;

the intention of holding versus selling an asset;

the forecast of undiscounted expected future cash flow over the asset s estimated useful life; and

if an impairment exists, the fair value of the asset or asset group.

Table of Contents

We did not have impairments of property and equipment in 2011, 2010 or 2009.

Accruals and Contingent Liabilities. We record accruals or liabilities including, but not limited to, insurance claims, asset retirement obligations, property taxes and potential legal claims. Accruals are made when our assessment indicates that it is probable that a liability has occurred and the amount of liability can be reasonably estimated. Such accruals may include estimates and are based on all known facts at the time and our assessment of the ultimate outcome. Among the many uncertainties that impact our estimates are the necessary regulatory requirements for operating gas storage facilities, costs of medical care associated with worker s compensation and employee health insurance claims, and the possibility of legal claims. Our estimates for contingent liability accruals are increased or decreased as additional information is obtained or resolution is achieved. Presently, there are no material accruals in these areas. Although the resolution of uncertainties has not historically had a material impact on our results of operations or financial condition, we cannot provide assurance that actual amounts will not vary significantly from estimated amounts.

Equity Compensation Plan Expense Recognitions. We recognize compensation expense for outstanding equity compensation awards granted under our Long Term Incentive Plan and similar plans sponsored by PAA. Under generally accepted accounting principles, we are required to estimate the fair value of our outstanding equity awards and recognize that fair value as compensation expense over the applicable service period. For awards that contain a performance condition, the fair value of the award is recognized as compensation expense only if the attainment of the performance condition is considered probable. See Note 12 to our consolidated financial statements for further discussion of our equity compensation plans.

Valuation of Derivative Financial Instruments. We are required to measure derivatives at fair value pursuant to FASB guidance, the estimates of derivative gains or losses for a particular period are unrealized and will most likely not reflect the realized derivative gain or loss upon settlement of the derivative. We estimate the fair value of our derivatives with quoted prices, internal records and information received from third parties. For derivatives that are not exchange traded, the estimates we derive are based on indicative broker quotations that are further validated with market observable inputs. Although the resolution of these uncertainties has not historically had a material impact on our results of operations or financial condition, we cannot provide assurance that actual amounts will not vary significantly from estimated amounts.

Recent Accounting Pronouncements

For a discussion of recent accounting pronouncements that will impact us, see Note 2 to our consolidated financial statements.

Results of Operations

PAA Ownership Transaction and Basis of Presentation

The tables below summarize our results of operations for the periods indicated. Due to the change in accounting basis that occurred as a result of the PAA Ownership Transaction, combining results of operations for 2009 periods prior to and subsequent to the PAA Ownership Transaction for purposes of comparison to 2010 results, without making appropriate adjustments, may not necessarily facilitate a meaningful analysis and would be inconsistent with relevant accounting and financial reporting authoritative guidance applicable to similar circumstances. As a result, we have elected to present pro forma results of operations for the year ended December 31, 2009 which have been prepared as if the PAA Ownership Transaction had occurred on January 1, 2009. Additionally, we have presented historical financial information for the periods from January 1, 2010 to September 2, 2010 and September 3, 2010 to December 31, 2010 for purposes of comparison to the comparable historical financial information for the periods prior to and subsequent to the PAA Ownership Transaction in 2009.

The pro forma information is based on assumptions that we believe are reasonable under the circumstances and are intended for illustrative purposes only. While not necessarily indicative of the results of the actual or future operations that would have been achieved had the PAA Ownership Transaction occurred on January 1, 2009, we believe this information provides a more meaningful basis of comparison for purposes of discussion of current period results as information is presented on a comparable accounting basis for complete fiscal periods. Pro forma adjustments reflected in the pro forma results for year ended December 31, 2009 impacted general and administrative expenses, interest expense and depreciation, depletion and amortization. Revenues and expense categories, other than those previously noted, were not materially impacted by the change in basis and amounts on a pro forma basis for the 2009 period are the summation of activity for the applicable 2009 historical periods prior to and subsequent from the PAA Ownership Transaction. Further discussion of the nature of the pro forma adjustments made is included as a part of this analysis. No pro forma adjustments were made attributable to the Partnership s May 2010 initial public offering.

Table of Contents

Year ended December 31, 2011 and year ended December 31, 2010

The following table includes our operating results for years ended December 31, 2011 and 2010 (amounts in thousands, except for average working storage capacity and monthly operating metrics):

	Year Ended December 31, 2011	Year Ended December 31, 2010	Favorable/(Unfavorable) Variance[1] 2011 - 2010 $	%
Revenues				
Firm storage services				
Reservation fees	$ 127,770	$ 85,651	$ 42,119	49%
Cycling fees and fuel-in-kind	8,411	5,314	3,097	58%
Hub services	9,806	6,190	3,616	58%
Natural gas sales	193,031		193,031	
Other	3,946	3,132	814	26%
Total revenue	342,964	100,287	242,677	242%
Storage related costs	(21,684)	(23,465)	1,781	8%
Natural gas sales costs	(183,408)		(183,408)	
Other operating costs (except those shown below)	(11,621)	(7,242)	(4,379)	(60)%
Fuel expense	(4,924)	(2,368)	(2,556)	(108)%
General and administrative expenses	(22,566)	(15,965)	(6,601)	(41)%
Other income / (expense)	5	(18)		
Equity compensation expense	4,046	2,747		
Acquisition related costs	4,055	251		
Insurance deductible related to property damage	500			
Mark-to-market of open derivative positions	(138)	(370)		
Adjusted EBITDA	$ 107,229	$ 53,857	$ 53,372	99%
Reconciliation to net income				
Adjusted EBITDA	$ 107,229	$ 53,857	$ 53,372	99%
Depreciation, depletion and amortization	(33,714)	(14,119)	(19,595)	(139)%
Interest expense, net of capitalized interest	(5,354)	(7,323)	1,969	27%
Income tax expense				
Equity compensation expense	(4,046)	(2,747)		
Acquisition related costs	(4,055)	(251)		
Insurance deductible related to property damage	(500)			
Mark-to-market of open derivative positions	138	370		
Net income	$ 59,698	$ 29,787	$ 29,911	100%
Operating Data:				
Net revenue margin [2]	$ 137,734	$ 76,452	$ 61,282	80%
Other operating expenses / G&A / Other	(30,505)	(22,595)	(7,910)	(35)%
Adjusted EBITDA	$ 107,229	$ 53,857	$ 53,372	99%
Average working storage capacity (Bcf)	71	47	24	51%
Monthly Operating Metrics ($/Mcf)				
Net revenue margin	$ 0.16	$ 0.14	$ 0.02	14%
Operating expenses / G&A / Other	(0.04)	(0.04)		

Adjusted EBITDA	$	0.12	$	0.10	$	0.02	20%

(1) Certain variance amounts and/or percentages were intentionally omitted.
(2) Net revenue margin equals total revenues less storage related costs, natural gas sales costs and mark-to-market of open derivative positions.

Revenues and Related Costs. As noted in the table above, our total revenue and related costs increased during the year ended December 31, 2011 (the 2011 period) when compared to the year ended December 31, 2010 (the 2010 period). The primary reasons for such increase are the completion of the Southern Pines Acquisition on February 9, 2011, results of PNG Marketing, incremental revenues attributable to the expansion of our working gas capacity at the Pine Prairie facility by approximately 8 Bcf and 10 Bcf during 2011 and 2010, respectively, and additional leasing of capacity or third party transportation assets impacting the 2011 period relative to the 2010 period. These and other significant variances related to these periods are discussed in more detail below:

Firm storage reservation fees Firm storage reservation fee revenues increased in the 2011 period as compared to the 2010 period, primarily due to the completion of the Southern Pines Acquisition and incremental revenues attributable to the expansion of our working gas capacity at the Pine Prairie facility that reflect the benefit of a full year contribution from the 10 Bcf of working gas capacity placed in service during the second quarter of 2010 and a partial year contribution from the 8 Bcf of working gas capacity placed in service during the second quarter of 2011.

Firm storage cycling fees and fuel-in-kind Firm storage cycling fees and fuel-in-kind revenues increased in the 2011 period as compared to the 2010 period primarily due to the increase in working gas capacity in-service from 2010 to 2011 as a result of the completion of the Southern Pines Acquisition.

Hub services Hub services increased in the 2011 period as compared to the 2010 period. Our hub services activities are generally short-term in nature and their timing is influenced by weather, operating disruptions, import activities and other conditions that result in temporary disruptions in supply and demand. The increase in hub services revenues in the 2011 period as compared to the 2010 period is primarily due to the increase in working gas capacity in-service from 2010 to 2011 as a result of the Southern Pines Acquisition and our Pine Prairie expansion efforts along with additional usage of capacity leased from third party transportation assets.

Natural gas sales Natural gas sales of approximately $193.0 million during the 2011 period relate to revenues from sales of natural gas by PNG Marketing.

Other Other revenues increased in the 2011 period as compared to the 2010 period primarily due to the receipt of a fixed monthly access fee from Plains Gas Solutions, LLC (formerly known as CDM Max, LLC), an affiliate of PAA, relating to a natural gas services agreement entered into during 2011.

Storage related costs Storage related costs decreased in the 2011 period as compared to the 2010 period. The decrease was primarily the result of a decrease in the amount of leased storage and a reduction in costs incurred to manage our storage capacity. This decrease was partially offset by an increase in leased transportation assets in the 2011 period as compared to the 2010 period.

Natural gas sales costs Natural gas sales costs of approximately $183.4 million during the 2011 period reflect the cost of natural gas sold by PNG Marketing.

Other Costs and Expenses. The significant variances are discussed further below:

Operating costs Field operating costs increased in the 2011 period as compared to the 2010 period. The increase is primarily related to the increase in working gas capacity in-service from 2010 to 2011 as a result of our expansion efforts at our Pine Prairie facility and the completion of the Southern Pines Acquisition. The 2011 period includes approximately $0.5 million of expense for the property insurance deductible related to the January 2011 operational incident and fire at our Bluewater facility.

Fuel expense Fuel expense increased in the 2011 period as compared to the 2010 period primarily due to the increase in in-service working gas capacity in 2011 as compared to 2010 as a result of the Southern Pines Acquisition and expansion efforts at our Pine Prairie facility.

General and administrative expenses General and administrative expenses increased in the 2011 period as compared to the 2010 period. The increase primarily resulted from the continued expansion of our business and growth in personnel costs, including equity compensation expense and the operation of our commercial optimization group for a full year in 2011, along with additional administrative costs associated with being a public company for a full year in 2011. Additionally, during the 2011 period we recognized approximately $2.7 million of equity compensation expense associated with awards granted by PAA compared to approximately $1.5 million in the 2010 period. Although we will not bear the economic burden of these awards, we benefit from the services underlying these awards. The 2011 period also includes approximately $4.1 million of acquisition and integration costs incurred in conjunction with the Southern Pines Acquisition. The 2010 period includes non-recurring costs of approximately $2.4 million associated with acquisition evaluation expenses, the start-up of our commercial optimization group and general and administrative expenses associated with our initial public offering efforts.

Depreciation, depletion and amortization Depreciation, depletion and amortization expense increased in the 2011 period as compared to the 2010 period. The increase resulted primarily from an increased amount of depreciable assets resulting from the Southern Pines acquisition and our internal growth projects, including the additional 10 Bcf and 11 Bcf of storage capacity placed into service at our Pine Prairie facility in April 2011 and April 2010, respectively. Additionally, amortization of intangible assets acquired in conjunction with the Southern Pines Acquisition was approximately $14.7 million during the 2011 period.

Interest expense, net of capitalized interest Interest expense, net of capitalized interest, decreased in the 2011 period when compared to the 2010 period. Interest expense, on a gross basis, increased to approximately $16.3 million in the 2011 period as compared to approximately $14.9 million in the 2010 period. The increase principally resulted from an increase in average outstanding debt balances in the 2011 period as compared to the 2010 period and was partially offset by a decrease in average interest rates in the 2011 period as compared to 2010 period. Capitalized interest was approximately $10.9 million and $7.6 million in the 2011 and 2010 periods, respectively. Capitalized interest increased primarily due to an increase in assets not yet in service as a result of the Southern Pines Acquisition.

Year ended December 31, 2010 and pro forma year ended December 31, 2009

The following table includes our operating results for the year ended December 31, 2010, the period from January 1, 2009 through September 2, 2009 and the period from September 3, 2009 to December 31, 2009 on a historical basis and for the year ended December 31, 2009 on a pro forma basis (amounts in thousands, except for average working storage capacity and monthly operating metrics). Information designated as Predecessor and Successor relate to the accounting periods preceding and succeeding the PAA Ownership Transaction. The Predecessor and Successor periods have been separated by a vertical line on the following table to highlight the fact that the financial information for such periods has been prepared under a different basis of accounting.

Table of Contents

	Successor Year Ended December 31, 2010	Pro Forma Year Ended December 31, 2009	Successor September 3, 2009 through December 31, 2009	Predecessor January 1, 2009 through September 2, 2009	Favorable/(Unfavorable) Variance[1] 2010 - 2009 Pro forma $	%
Revenues						
Firm storage services						
Reservation fees	$ 85,651	$ 62,535	$ 22,919	$ 39,616	$ 23,116	37%
Cycling fees and fuel-in-kind	5,314	4,086	1,053	3,033	1,228	30%
Hub services	6,190	4,625	1,637	2,988	1,565	34%
Other	3,132	934	(358)	1,292	2,198	235%
Total revenue	100,287	72,180	25,251	46,929	28,107	39%
Storage related costs	(23,465)	(15,795)	(7,003)	(8,792)	(7,670)	(49)%
Other operating costs (except those shown below)	(7,242)	(8,077)	(3,257)	(4,820)	835	10%
Fuel expense	(2,368)	(2,394)	(578)	(1,816)	26	1%
General and administrative expenses	(15,965)	(8,885)	(4,083)	(3,562)	(7,080)	(80)%
Other income / (expense)	(18)	456	(2)	458	(474)	(104)%
Equity compensation expense	2,747	1,771	1,467	304		
Acquisition related costs	251					
Mark-to-market of open derivative positions	(370)	370	370			
Adjusted EBITDA	$ 53,857	$ 39,626	$ 12,165	$ 28,701	$ 14,231	36%
Reconciliation to net income						
Adjusted EBITDA	$ 53,857	$ 39,626	$ 12,165	$ 28,701	$ 14,231	36%
Depreciation, depletion and amortization	(14,119)	(11,341)	(3,578)	(8,054)	(2,778)	(24)%
Interest expense, net of capitalized interest	(7,323)	(11,676)	(4,262)	(4,352)	4,353	37%
Income tax expense		(473)		(473)		
Equity compensation expense	(2,747)	(1,771)	(1,467)	(304)		
Acquisition related costs	(251)					
Mark-to-market of open derivative positions	370	(370)	(370)			
Net income	$ 29,787	$ 13,995	$ 2,488	$ 15,518	$ 15,792	113%
Operating Data:						
Net revenue margin [2]	$ 76,452	$ 56,755	$ 18,618	$ 38,137	$ 19,697	35%
Other operating expenses / G&A / Other	(22,595)	(17,129)	(6,453)	(9,436)	(5,466)	(32)%
Adjusted EBITDA	$ 53,857	$ 39,626	$ 12,165	$ 28,701	$ 14,231	36%
Average working storage capacity (Bcf)	47	38	40	36	9	24%
Monthly Operating Metrics ($/Mcf)						
Net revenue margin	$ 0.14	$ 0.12	$ 0.12	$ 0.13	$ 0.02	17%
Operating expenses / G&A / Other	(0.04)	(0.03)	(0.03)	(0.03)	(0.01)	(33)%
Adjusted EBITDA	$ 0.10	$ 0.09	$ 0.09	$ 0.10	$ 0.01	11%

(1) Certain variance amounts and/or percentages were intentionally omitted.

(2) Net revenue margin equals total revenues less storage related costs and mark-to-market of open derivative positions.

Table of Contents

Pro Forma Adjustments

Pro forma adjustments reflected in the information above include:

An increase in general and administrative expenses of approximately $1.2 million for the pro forma year ended December 31, 2009, to reflect an increase in personnel costs allocated to us from PAA as a result of an increase in services provided on our behalf.

A net increase in interest expense, net of capitalized interest of approximately $3.1 million for the pro forma year ended December 31, 2009. In conjunction with the PAA Ownership Transaction amounts outstanding under our credit facilities were extinguished and replaced with a related party note payable to PAA which accrued interest at a rate of 6.5%, which was higher than historical rates of interest on our predecessor s extinguished credit facilities. The increase in interest rate results in incremental interest expense in the 2009 period on a pro forma basis. This increase was partially offset by an increase in capitalized interest.

A net decrease in depreciation, depletion and amortization expense of approximately $0.3 million for the pro forma year ended December 31, 2009. Depreciation expense increased by $0.6 million in the pro forma year ended December 31, 2009 due to fair value adjustments recorded in conjunction with the PAA Ownership Transaction, partially offset by a revision in estimates of useful lives. Amortization expense decreased by $0.9 million in the pro forma year ended December 31, 2009 due to changes in the composition of our intangible assets, including debt issuance costs, and their associated estimated useful lives.

Revenues and Related Costs. As noted in the table above, our total revenue increased during the year ended December 31, 2010 (the 2010 period) when compared to the year ended December 31, 2009 on a pro forma basis (the 2009 pro forma period). The primary reason for such increase is the placement into service of an additional 8 Bcf and 10 Bcf of working gas storage capacity at our Pine Prairie facility during the second quarters of 2009 and 2010, respectively. Additionally, total revenues and storage related costs increased due to additional leasing of third party storage and transportation capacity in 2010. These and other significant variances related to these periods are discussed in more detail below:

Firm storage reservation fees Firm storage reservation fee revenues increased for the 2010 period as compared to the 2009 pro forma period, primarily due to the placement into service of an additional 8 Bcf and 10 Bcf of working gas capacity at our Pine Prairie facility during the second quarters of 2009 and 2010, respectively, which resulted in approximately $20 million in incremental revenues generated by our Pine Prairie facility during the 2010 period. Revenues from firm storage reservation fees were also positively impacted by loan activities and additional revenue generating activities associated with increased amounts of leased storage and transportation capacity. See Storage related costs below.

Firm storage cycling fees and fuel-in-kind Firm storage cycling fees and fuel-in-kind revenues increased in the 2010 period as compared to the 2009 pro forma period. The increase was primarily driven by an increase in the period-over-period average natural gas price of approximately 10% in the 2010 period as compared to the 2009 pro forma period, which increased our fuel-in-kind revenues. Such increase was partially offset by a reduction in cycling volumes.

Hub services Hub services increased in the 2010 period as compared to the 2009 pro forma period. This increase primarily related to increased wheeling and balancing services as a result of utilizing leased transportation capacity during the 2010 period to augment the service capabilities of our owned assets. See Storage related costs below. Our hub services activities are generally short-term in nature and their timing and extent of activity are influenced by weather, operating disruptions, import activities and other conditions that result in temporary disruptions in supply, demand and working gas capacity.

Other Other revenue for each of the periods consists primarily of crude oil sales and activities associated with natural gas storage-related futures derivative positions. Crude oil sales increased in the 2010 period as compared to the 2009 pro forma period by approximately $1.6 million. The increase reflected higher average realized prices in 2010 versus the prior year period, combined with an increase in production in 2010. The 2010 increase in production was primarily due to our completion of a new well drilled as part of our ongoing liquids removal efforts at our Bluewater facility. The 2010 period and the 2009 pro forma period each include losses of approximately $0.4 million associated with a natural gas storage-related futures derivative position which was closed out during the second quarter of 2010 at a realized loss of approximately $0.8 million. The 2010 period also reflects a gain of approximately $0.6 million associated with sales of excess fuel inventory and natural gas acquired for operational purposes in the fourth quarter of 2010.

Table of Contents

Storage related costs Storage related costs increased in the 2010 period as compared to the 2009 pro forma period due to an increase in the amount of storage and transportation capacity leased from third parties. In addition, we experienced higher costs as a result of increased loan transactions in 2010 as compared to 2009. Further, during the 2010 period we released a portion of our leased transportation capacity to third parties through August 2011. The 2010 period reflects a loss of approximately $0.4 million representing the portion of the reservation charges that we do not anticipate recovering over the remaining period of the capacity release. See Firm storage reservation fees above.

Other Costs and Expenses. The significant variances are discussed further below:

Operating costs Field operating costs decreased in the 2010 period as compared to the 2009 pro forma period. The decrease is primarily related to a decrease in property tax expense attributable to revisions of estimated property tax obligations.

Fuel expense Fuel expense did not change significantly in the 2010 period as compared to the 2009 pro forma period.

General and administrative expenses General and administrative expenses increased in the 2010 period as compared to the 2009 pro forma period. The approximately $7.1 million increase resulted from the continued expansion of our business and growth in personnel costs, including equity compensation expense and the establishment of our commercial optimization group, along with additional administrative costs associated with being a public company. Increased costs in 2010 reflect approximately $2.4 million associated with acquisition evaluation expenses, the start-up of our commercial optimization group and internal general and administrative expenses associated with our initial public offering efforts. Additionally, the 2010 period includes approximately $1.5 million of equity compensation expense associated with awards granted by PAA to certain officers of PAA that will be settled in PNG common units owned by PAA upon vesting. Although the entire economic burden of these agreements will be borne solely by PAA, since these individuals also serve as officers of PNG and PNG benefits as a result of the services they provide, we are required to reflect the compensation expense associated with these awards in our financial statements.

Other income / (expense) Other income / (expense) for the 2009 pro forma period was comprised primarily of interest income and ineffectiveness associated with an interest rate swap agreement. The reduction of other income / (expense) for the 2010 period was driven by the termination of the swap agreement in conjunction with the PAA Ownership Transaction and, following the PAA Ownership Transaction, a significant reduction in the amount of cash balances carried by us, which resulted in a decrease in interest income.

Depreciation, depletion and amortization Depreciation, depletion and amortization expense increased in the 2010 period as compared to the 2009 pro forma period. Depreciation increased by approximately $2.8 million, primarily as a result of an increased amount of depreciable assets resulting from our internal growth projects including the additional 8 Bcf and 10 Bcf of storage capacity placed into service in April 2009 and April 2010, respectively. Depreciation, depletion and amortization expense includes amortization of debt issue costs and intangibles of $2.3 million and $2.6 million in the 2010 period and 2009 pro forma period, respectively.

Interest expense, net of capitalized interest Interest expense decreased in the 2010 period when compared to the 2009 pro forma period. The decrease principally resulted from decreases in both average debt balances outstanding and average interest rates in the 2010 period as compared to the 2009 pro forma period. Capitalized interest was approximately $7.6 million and $15.6 million in the 2010 period and the 2009 pro forma period, respectively, with decreases in both average debt balances outstanding and average interest rates as well as an increase in in-service capacity at our Pine Prairie facility period over period.

Income tax expense As a partnership we are not subject to U.S. federal income taxes, rather, the tax effect of our operations is passed through to our partners and unitholders. Our income tax expense consists principally of state income taxes calculated on an apportionment basis. The income tax expense is lower in the 2010 period when compared to the 2009 pro forma period due to the combined impact of the expansion in our areas of operations outside of the applicable state, and ownership changes that resulted in our inclusion as a consolidated subsidiary of PAA.

Table of Contents

Periods from January 1 to September 2, 2010 and 2009 and from September 3 to December 31, 2010 and 2009

The following table includes our operating results for the historical periods from January 1 to September 2, 2010 and 2009 and from September 3 to December 31, 2010 and 2009 (amounts in thousands, except for average working storage capacity and monthly operating metrics). Historical information for the periods from January 1 to September 2, 2010 and September 3 to December 31, 2010 is unaudited. Information designated as Predecessor and Successor relate to the accounting periods preceding and succeeding the PAA Ownership Transaction. The Predecessor and Successor periods have been separated by a vertical line on the following table to highlight the fact that the financial information for such periods has been prepared under a different basis of accounting.

[Table of Contents](#)

	Successor		Predecessor		Favorable/(Unfavorable) Variance (1)			
	September 3, 2010 through December 31, 2010	January 1, 2010 through September 2, 2010	September 3, 2009 through December 31, 2009	January 1, 2009 through September 2, 2009	September through December 2010 to 2009		January through September 2010 to 2009	
					$	%	$	%
Revenues								
Firm storage services								
Reservation fees	$ 30,994	$ 54,657	$ 22,919	$ 39,616	$ 8,075	35%	$ 15,041	38%
Cycling fees and fuel-in-kind	1,874	3,440	1,053	3,033	821	78%	407	13%
Hub services	2,792	3,398	1,637	2,988	1,155	71%	410	14%
Other	1,616	1,516	(358)	1,292	1,974	551%	224	17%
Total revenue	37,276	63,011	25,251	46,929	12,025	48%	16,082	34%
Storage related costs	(8,878)	(14,587)	(7,003)	(8,792)	(1,875)	(27)%	(5,795)	(66)%
Other operating costs (except those shown below)	(2,719)	(4,523)	(3,257)	(4,820)	538	17%	297	6%
Fuel expense	(961)	(1,407)	(578)	(1,816)	(383)	(66)%	409	23%
General and administrative expenses	(6,207)	(9,758)	(4,083)	(3,562)	(2,124)	(52)%	(6,196)	(174)%
Other income/(expense)	(7)	(11)	(2)	458	(5)	(250)%	(469)	(102)%
Equity compensation expense	1,937	810	1,467	304	470		506	
Acquisition related costs	251				251			
Mark-to-market of open derivative positions		(370)	370		(370)			
Adjusted EBITDA	$ 20,692	$ 33,165	$ 12,165	$ 28,701	$ 8,527	70%	$ 4,464	16%
Reconciliation to net income								
Adjusted EBITDA	$ 20,692	$ 33,165	$ 12,165	$ 28,701	$ 8,527	70%	$ 4,464	16%
Depreciation, depletion and amortization	(5,065)	(9,054)	(3,578)	(8,054)	(1,487)	(42)%	(1,000)	(12)%
Interest expense, net of capitalized interest	(1,028)	(6,295)	(4,262)	(4,352)	3,234	76%	(1,943)	(45)%
Income tax expense				(473)			473	100%
Equity compensation expense	(1,937)	(810)	(1,467)	(304)	(470)		(506)	
Acquisition related costs	(251)				(251)			
Mark-to-market of open derivative positions		370	(370)		370		370	
Net income	$ 12,411	$ 17,376	$ 2,488	$ 15,518	$ 9,923 &			