

PAA NATURAL GAS STORAGE LP

Form 10-K

March 02, 2011

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**UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
Form 10-K**

(Mark One)

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

For the fiscal year ended December 31, 2010

or

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

(State or other jurisdiction of
incorporation or organization)

27-1679071

(I.R.S. Employer
Identification No.)

333 Clay Street, Suite 1500, Houston, Texas

(Address of principal executive offices)

77002

(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

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes No

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

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

Large accelerated filer Accelerated filer Non-accelerated filer Smaller reporting company
(Do not check if a 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

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 \$315 million on June 30, 2010, based on \$23.83 per unit, the closing price of the Common Units as reported on the New York Stock Exchange on such date.

At February 28, 2011, there were outstanding 59,184,450 Common Units.

DOCUMENTS INCORPORATED BY REFERENCE

NONE

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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, inter forecast, as well as similar expressions and statements 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. These factors include, but are not limited to:

the impact of operational 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 and cavern temperature variances;

risks related to the 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;

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;

significantly reduced volatility in natural gas markets for an extended period of time;

factors affecting demand for natural gas and natural gas storage services and the rates we are able to charge for such services;

our ability to maintain or replace expiring storage contracts at attractive rates and on other favorable terms;

the effects of competition;

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;

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

the effectiveness of our risk management activities;

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

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

increased costs or unavailability of insurance;

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

future developments and circumstances at the time distributions are declared; and

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

Other factors, described herein, or 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.

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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 subsidiaries.

Our business consists of the acquisition, development, operation and commercial management of natural gas storage facilities. As of December 31, 2010, we owned and operated two natural gas storage facilities located in Louisiana and Michigan. On February 9, 2011, we closed the acquisition of a third natural gas storage facility in Mississippi. See Recent Developments. 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

On May 5, 2010, we completed our initial public offering. As a result of this transaction, we issued 13.5 million common units to the public, representing an approximate 23% ownership interest in the Partnership. In exchange for contributing its natural gas storage business and \$16.4 million of intercompany indebtedness, PAA received a 2% general partner interest, 18.1 million common units, 13.9 million Series A subordinated units and 11.5 million Series B subordinated units, as well as incentive distribution rights. In August 2010, our partnership agreement was amended to reflect the exchange by PAA of two million Series A subordinated units for two million newly issued Series B subordinated units. As a result, at December 31, 2010, PAA owned an aggregate direct and indirect 77% ownership interest in PNG comprised of the general partner's 2% interest, 18.1 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 by our unitholders.

In connection with the Southern Pines Acquisition completed on February 9, 2011, we issued 27.6 million common units in a private placement of which 10.2 million units were issued to PAA. As a result of this transaction, as of February 9, 2011, PAA owned an aggregate 64% interest in us consisting 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. See Recent Developments. The diagram below illustrates the structure of PAA Natural Gas Storage, L.P. at February 28, 2011.

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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 to 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.

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. Including the acquisition of Southern Pines in February 2011 and expansions that are currently permitted and under construction, we have the potential to increase our capacity from approximately 50 billion cubic feet (Bcf) of working capacity at December 31, 2010 to an aggregate of over 110 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 are seeking acquisition or development opportunities that will be accretive (or 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.

Utilizing a portion of our owned and leased storage capacity to enhance our commercial management activities. Similar to the business model successfully employed by PAA, and

without altering our basic commercial strategy of committing a high percentage of our storage capacity under firm multi-year storage contracts at attractive rates, during 2010 we established a dedicated commercial marketing group that will capture market opportunities by leasing storage capacity for our own account and engaging in related commercial marketing activities.

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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 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 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 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. For example, as a result of the timing of growth in Adjusted EBITDA related to the Southern Pines Acquisition, we expect our long-term debt to Adjusted EBITDA multiple will be above our target range until the second half of 2012. See [Recent Developments](#).

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](#). 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.

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 as well as the primary consumer and industrial markets in the Gulf Coast, Midwest, Northeast and Southeast. After giving effect to the Southern Pines Acquisition (see [Recent Developments](#)), our three facilities have permitted aggregate peak injection and withdrawal capacity of 2.9 Bcf per day and 5.6 Bcf per day, respectively. Upon the completion of current expansion activities, these capacities will increase to 4.1 Bcf per day of peak rate injection capacity and 6.4 Bcf per day of peak rate withdrawal capacity. Utilization of a portion of our existing and planned capacity is subject to market demand and receipt of appropriate governmental approvals.

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

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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 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 facilities significantly beyond their current size. In addition, because the existing infrastructure at two of our 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 specialized knowledge of natural gas storage 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.

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 equity market capitalization, which was approximately \$8.9 billion as of December 31, 2010. PAA'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 its ownership interest in us, PAA is engaged in the transportation, storage, terminalling and marketing of crude oil, refined products and liquefied petroleum gas and other natural gas-related petroleum products. PAA's assets include approximately 16,000 miles of pipelines, approximately 90 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 approximately \$14 billion and increased the annualized distribution on its limited partner units by over 100%, from \$1.80 per unit as of PAA's initial public offering to \$3.83 per unit for the distribution paid in February 2011.

Our partnership owns all of the natural gas storage business and assets formerly owned by PAA 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) following the Southern Pines Acquisition and related financings, PAA has a significant economic stake in us and a commensurate incentive to promote and support the successful execution of our growth plan and strategy. See Recent Developments.

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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***Acquisition of SG Resources Mississippi, L.L.C.***

On February 9, 2011, we acquired 100% of the equity interests in SG Resources Mississippi, L.L.C. (the Southern Pines Acquisition), which entity owns the Southern Pines Energy Center natural gas storage facility (Southern Pines), for total consideration of approximately \$746 million, subject to certain post-closing adjustments.

Southern Pines is a FERC-regulated, high-performance, salt-cavern natural gas storage facility located in Greene County, Mississippi. The facility's current permits allow for 40 Bcf of working capacity from four storage caverns. The facility commenced service in 2008 and three caverns have been placed into service, which are serving over 17 Bcf of customer contracts. These caverns are being expanded over time to their permitted capacity of 10 Bcf each. The fourth cavern is currently being drilled. Drilling is expected to be completed during the second quarter of 2011, at which point leaching will commence. The fourth cavern is anticipated to be placed into service in the third quarter of 2012. The facility has the capacity for further expansion beyond 40 Bcf, if warranted by market demand and subject to receipt of required permits. Based on our estimates of current working capacity and the projected working capacity to be created, Southern Pines is fully contracted for the 2011/2012 and 2012/2013 storage seasons and substantially contracted for the 2013/2014 and 2014/2015 storage seasons (storage seasons run from April–March). Working capacity of salt cavern facilities is dependent, among other factors, on cavern temperature and pressure as well as the leaching rate achieved to create incremental space. As a result, aggregate capacity available to serve existing contracts may at times exceed or lag aggregate contractual obligations. As of January 1, 2011, existing contracts at Southern Pines had a remaining weighted average term of approximately 5.5 years. As a result, we believe that Southern Pines will generate stable and predictable, low-risk, fee-based revenues.

Southern Pines has an aggregate of 48,000 horsepower of compression and is permitted to accommodate injection and withdrawal capabilities of approximately 1.2 Bcf and approximately 2.4 Bcf of gas per day, respectively. Southern Pines is designed to accommodate daily injection and withdrawal capabilities of 1.5 Bcf and 3.0 Bcf, respectively. Utilization of such incremental capacity is subject to market demand and would require governmental approval. Southern Pines is connected directly or indirectly to eight major natural gas pipelines servicing the Gulf Coast, Northeast, Mid-Atlantic and Southeastern U.S. markets.

In connection with the transaction, we raised \$800 million of capital, which funded the purchase price, estimated closing and integration costs and the first 18 months of expected expansion capital related to Southern Pines. This financing was composed of \$600 million of equity and \$200 million of debt. The equity financing included a private placement of 17.4 million PNG common units to third-party purchasers for net proceeds of approximately \$370 million and the sale of 10.2 million PNG common units to PAA for net proceeds of approximately \$230 million, including PAA's proportionate general partner contribution of \$12 million. The debt financing consisted of PNG issuing a three-year, \$200 million note to PAA at an interest rate of 5.25% per annum. The note will mature on February 9, 2014. As a result of the equity financing, PAA's aggregate equity ownership in us decreased to 64% from 77% prior to the transaction. PAA continues to own 100% of our general partner and our incentive distribution rights. During the fourth quarter of 2010, we made a deposit related to the Southern Pines Acquisition of \$20 million which was reflected as restricted cash on our consolidated balance sheet as of December 31, 2010. Because of the ongoing expansion activities and lead time necessary to increase Southern Pines contributions to Adjusted EBITDA, we anticipate we will be outside the parameters of our targeted credit profile until the second half of 2012.

Bluewater Incident

On January 12, 2011, we experienced an operational incident and related fire at our Bluewater natural gas storage facility located in St. Claire County, Michigan. Facility damage from the incident was limited to the portion of Bluewater's gas handling facility that removes liquids from natural gas that is withdrawn from the larger of Bluewater's

two storage reservoirs before such gas is injected into pipelines for transportation. As a result, the amount of gas that can be withdrawn from that storage reservoir has been temporarily limited. Gas is still able to be withdrawn from the other storage reservoir and we do not expect that our ability to

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inject gas into either reservoir will be impacted for any extended period. Through the utilization of these capabilities, our leased storage in the market area and other operational and commercial alternatives, we have to date been able to meet all of our customers' contractual requirements. Based on our current expectations of customer demands, we expect to be able to continue to meet our obligations throughout the remainder of the withdrawal season, which typically ends on March 31st. Because this incident is not expected to materially impact Bluewater's injection capabilities, we do not anticipate any material issues in satisfying our customer obligations during the injection season, which follows the withdrawal season and typically ends on September 30th.

Subject to receiving the necessary regulatory clearances and permits, we are targeting to have the damaged portion of the facility back in service by October 2011, which should return Bluewater to fully functional operation for the balance of the 2011/2012 storage season. We currently estimate the cost of the reconstruction will be in the range of \$3.5 to \$5 million and we have a \$500,000 insurance deductible for property damage. As a result of this incident, we have had to defer until early 2012 our planned capital program for Bluewater with respect to the drilling of two additional liquid withdrawal wells.

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.

Natural Gas Demand. During the period from 2001 through 2010, 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 ten year period ended November 2010. The chart also includes EIA forecasted data for December 2010, and calendar years 2011 and 2012, which suggests relatively flat overall consumption of natural gas for the next two years.

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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. 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 an average of approximately 3.7% per annum during the four year period from January 1, 2007 through December 31, 2010.¹ By comparison, EIA data also indicates that 2009 production from shale gas wells was approximately 3.1 trillion cubic feet (Tcf), representing an approximate 142% increase over 2007 levels. At the time of this report, 2010 production estimates by component (i.e. shale gas) were not available from EIA.

In addition to the emergence of domestic shale plays as a significant supply source, over the past several years the U.S. has developed significant infrastructure for the import of liquefied natural gas (LNG). Total LNG import capacity of U.S. infrastructure has increased to approximately 16 Bcf per day; however, because LNG suppliers have been able to obtain more favorable prices in global markets outside of the U.S., LNG imports into the U.S. have decreased from a peak of 2.1 Bcf a day in 2007 to less than 1.2 Bcf per day in 2009 and 2010, per EIA and other published daily data sources.

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, 2010 to December 31, 2010, U.S. consumption reached peak use of more than 110 Bcf on January 5, while the lowest daily consumption during this same period was approximately 46 Bcf on September 5, 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 56 Bcf to 63 Bcf. Natural gas storage (and to a lesser extent imported natural gas from Canada and LNG supplies) 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 \$0.50-\$4.75 per MMBtu, with the high end of that range occurring during the 2006-2007 timeframe. However, during the past six months, seasonal spreads fell to as low as \$0.43, their lowest point since 2004. In addition, lower short term spreads and basis differentials have reduced overall market volatility, which negatively impacts storage demand and value.

¹ Reported production per EIA was used through October 2010. For November and December 2010, reported production volume from November and December 2009, respectively, were used as proxies for the final two months of 2010.

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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 two years, (ii) increased natural gas supplies due to production from shale resources, (iii) lower basis differentials due to expansion of natural gas transportation infrastructure in the U.S. over the last five years, and (iv) abnormal seasonal weather patterns resulting in decreased seasonal price spreads.

Supply of Storage Capacity. Another 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 generally increased over the last six years, climbing from 91% in 2005 to 99% in 2009 and then settling down to 95% in 2010, in part due to a 4.1% increase in peak capacity relative to 2009 levels. Despite the increase in storage capacity and a warmer than normal summer in 2010, storage inventories reached a record peak level of 3.84 Tcf in November of 2010.

	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%

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, lower natural gas demand levels 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, 2010 we owned a 100% interest in two natural gas storage facilities: the Pine Prairie facility, which is a recently constructed, high-deliverability salt-cavern natural gas storage complex located in Evangeline Parish, Louisiana, and the Bluewater facility, which is 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 Pine Prairie and Bluewater storage facilities as of December 31, 2010:

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Facility Name and Type	Working Gas Capacity (Bcf)	Peak Injection Rate (Bcf/d)	Peak	
			Withdrawal Rate (Bcf/d)	Compression (Horsepower)
Pine Prairie (salt-cavern)				
Existing facility	24	1.2	2.4	48,000
Planned & permitted expansion	21 ⁽¹⁾	1.2 ⁽²⁾	0.8 ⁽²⁾	50,500 ⁽³⁾
Subtotal	45	2.4	3.2	98,500
Bluewater (depleted reservoir) ⁽⁵⁾				
Existing facility	26	0.5	0.8	13,350
Planned expansion	2 ⁽⁴⁾			
Subtotal	28	0.5	0.8	13,350
Total (both facilities) ^{(5) (6)}	73	2.9	4.0	111,850

(1) We expect to place 7.0 to 7.5 Bcf into service in the second quarter of 2011 and an additional 10 Bcf by mid-2012 and the final 3 Bcf will be added ratably through 2016.

(2) We expect to complete these expansions of peak injection and withdrawal capabilities by mid-2011.

(3) Of this incremental permitted capacity, we expect the installation of 23,000 horsepower to be completed by mid-2011, and up to an additional 17,250 horsepower to be in place by mid-2012.

(4) We expect to place this expansion in working gas capacity into service ratably over a 9 to 10-year period in connection with our ongoing liquids removal project.

(5) See Recent Developments for discussion of an incident in January 2011 that is expected to have a temporary limitation on Bluewater's ability to withdraw or inject natural gas at the indicated peak rates.

(6) See Recent Acquisition below for discussion of the acquisition of the Southern Pines facility, which was acquired on February 9, 2011 and is not included in the table above.

Pine Prairie. As a strategically-located, high-deliverability storage facility, Pine Prairie has attracted 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, which is the delivery point for New York Mercantile Exchange (NYMEX) natural gas futures contracts and is located approximately 50 miles southeast of Pine Prairie;

the Carthage Hub in east Texas, which is located approximately 150 miles northwest of Pine Prairie; and

the Perryville Hub in north Louisiana, which is located approximately 130 miles north of Pine Prairie.

Additionally, in January 2011, the CME Group, which owns the NYMEX, announced the introduction of three new natural gas futures contracts for physical delivery at Pine Prairie. The contracts began trading in February 2011 on the NYMEX floor and electronically through CME Globex and will be available for clearing services through CME ClearPort.

Pine Prairie's pipeline header system, which includes an aggregate of 74 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

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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 has a total current working gas storage capacity of 24 Bcf in three caverns, and planned expansions that will increase Pine Prairie's total capacity to 42 Bcf by mid-2012 and 45 Bcf by mid-2016 (see table above). 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 facility significantly beyond our current permitted capacity of 48 Bcf. Taking these considerations into account and with certain infrastructure modifications, we currently estimate that Pine Prairie could support in excess of 15 salt caverns and an aggregate storage capacity of over 150 Bcf.

In October 2010 we filed an application for a permit from the FERC to expand Pine Prairie's working capacity up to 80 Bcf. The incremental 32 Bcf would be comprised of expanding four existing caverns by an aggregate 8 Bcf through low-cost fill and dewater operations and adding two additional caverns of 12 Bcf each, increasing the total caverns at Pine Prairie to seven caverns.

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.

As indicated in the table above, Bluewater has total working gas storage capacity of approximately 26 Bcf in two depleted reservoirs and we expect to increase Bluewater's working gas capacity by 2 Bcf ratably over a 9 to 10-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.

Recent Acquisition

On February 9, 2011, we closed the Southern Pines Acquisition. See Recent Developments. Following is a description of the principal asset acquired in the Southern Pines Acquisition.

Southern Pines. Southern Pines is a FERC-regulated, high-performance, salt-cavern natural gas storage facility located in Greene County, Mississippi. The facility's permits allow for 40 Bcf of working capacity from four storage caverns. The facility commenced service in 2008 and three caverns have been placed into service, which are serving over 17 Bcf of customer contracts. These caverns are being expanded over time to their permitted capacity of 10 Bcf each. The fourth cavern is currently being drilled. Drilling is expected to be completed during the second quarter of 2011, at which point leaching will commence. The fourth cavern is anticipated to be placed into service in the third quarter of 2012. The facility has the capacity for further expansion beyond 40 Bcf, if warranted by market demand and subject to availability of additional permits.

Southern Pines has an aggregate of 48,000 horsepower of compression and is permitted to accommodate daily injection and withdrawal capabilities of approximately 1.2 Bcf and approximately 2.4 Bcf of gas per day, respectively. Southern Pines is designed to accommodate daily injection and withdrawal capabilities of 1.5 Bcf and 3.0 Bcf, respectively, but the utilization of such incremental capacity is subject to market demand and would require governmental approval. Southern Pines is connected directly or indirectly to 8 major natural gas pipelines servicing the Gulf Coast, Northeast, Mid-Atlantic and Southeastern U.S. markets.

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 Federal Energy

Regulatory Commission, or FERC, rate-making policies, which currently permit our facilities to charge market-based rates for our services.

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We generate revenue almost exclusively through the provision of fee-based gas storage services to our customers. For the year ended December 31, 2010, approximately 97% of our total revenue was derived from fee-based storage activities, with the remaining approximately 3% primarily attributable to the sale of liquid hydrocarbons incidentally produced in connection with the operation of our depleted reservoir storage facilities at Bluewater as well as other fuel and derivative related net gains and losses. Our revenues from fee-based gas storage services are derived from both firm storage services and hub services.

Firm Storage Services. Firm storage services include (i) storage services pursuant to which customers receive the assured or firm right to store gas in our facilities over a multi-year period and (ii) seasonal park and loan services pursuant to which customers receive the firm right to store gas in (park), or borrow gas from (loan), our facilities on a seasonal basis. 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. At Pine Prairie, our firm storage contracts typically have terms of 3 to 5 years, while at Bluewater terms generally range from 1 to 3 years. As of December 31, 2010, the weighted average remaining tenor of our existing portfolio of firm storage contracts is approximately 3.0 years at Pine Prairie and approximately 2.1 years at Bluewater. At Southern Pines, acquired in February 2011, existing contracts have a remaining weighted average term of approximately 5.5 years as of January 1, 2011. Under our firm storage contracts, we also typically collect a cycling fee based on the volume of natural gas nominated for injection and/or withdrawal and retain a small portion of natural gas nominated for injection as compensation for our fuel use. For the year ended December 31, 2010, approximately 91% of our total revenue was derived from firm storage services.

Hub Services. We also generate revenue from the provision of hub services at our facilities. 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) non-seasonal 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. For the year ended December 31, 2010, approximately 6% of our total revenue was derived from hub services.

We believe that the high percentage of our baseline cash flow derived from fixed-capacity reservation fees under firm 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.

Additionally, without altering our basic commercial strategy of committing a high percentage of our storage capacity under multi-year storage contracts, during 2010 we formed a dedicated commercial marketing group in order to capture short-term market opportunities by utilizing a portion of our owned or leased storage capacity for our own account and engaging in related commercial marketing activities. Through these transactions, we will 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.

Customers

We provide storage services to a broad mix of customers including LDCs, electric utilities, pipelines, direct industrial users, electric power generators, marketers, producers, LNG importers and affiliates of such entities. LDCs use storage services for seasonal balancing, to meet peak day deliveries and ensure reliability. Pipelines use storage services to manage short-term operational balancing requirements. Power generators, marketers and producers

generally use storage services for short-term balancing, to manage risk and to take advantage of the pricing differential between near-term and long-term natural gas. LNG importers use storage services to insure they have adequate storage capacity to accommodate imported LNG cargoes.

As of December 31, 2010 and excluding contracts with a future start date, Pine Prairie had 16 customers with firm storage contracts and Bluewater had 17 customers with firm storage contracts. For the year ended December 31, 2010, Iberdrola Renewables, Inc., Guardian Pipeline, LLC and Anadarko Energy Services accounted for approximately 13%, 9% and 8% of our revenues, respectively. As of closing on February 9, 2011, Southern Pines had 15 customers with firm storage contracts. The number of active hub services customers at each facility fluctuates throughout the course of the year depending on market conditions and other factors.

Contracts

See Our Operations.

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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 competes 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, while Bluewater competes with several Midwest utility and pipeline storage providers. Southern Pines competes with many of the same facilities and pipelines as Pine Prairie.

Regulation

Our operations are 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 individual participants. The failure to comply with such laws and regulations can result in substantial penalties. The regulatory burden on our operations increases our cost of doing business and, consequently, affects our profitability. Except for certain exemptions that apply to smaller companies, however, we do not believe that we are affected by these laws and regulations in a significantly different manner than are our competitors.

Following is a discussion of certain laws and regulations affecting us. However, our unitholders should not rely on such discussion as an exhaustive review of all regulatory considerations affecting our operations.

Our natural gas storage assets are subject to several kinds of regulation. 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. The following is a summary of the kinds of regulation that may impact our operations.

Natural Gas Storage Regulation

Interstate Regulation. Our natural gas storage facilities are classified as natural-gas companies under the Natural Gas Act of 1938 (NGA), and are therefore subject to regulation by the FERC. The NGA requires that tariff rates for gas storage facilities be just and reasonable and non-discriminatory. The FERC has authority to regulate rates and charges for natural gas transported and stored in U.S. interstate commerce or sold by a natural gas company in interstate commerce for resale. The FERC has granted our natural gas storage facilities market-based rate authority. Market-based rate authorization allows us to negotiate rates with individual customers based on market demand, which Pine Prairie, Bluewater and Southern Pines then make public via postings on their respective websites.

The FERC also has authority over the construction and operation of U.S. pipeline transportation and storage facilities and related facilities used in the transportation, storage and sale of natural gas in interstate commerce, including the extension, enlargement or abandonment of such facilities. In addition, the FERC's authority extends to maintenance of accounts and records, terms and conditions of service, depreciation and amortization policies, 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.

Standards of Conduct for Transmission Providers. Historically, the FERC's standards of conduct regulations (now vacated) generally restricted access to U.S. interstate natural gas storage customer data by marketing and other energy affiliates, and placed certain conditions on services provided by U.S. storage facility operators to their affiliated gas marketing entities. The standards of conduct did not apply, however, to natural gas storage providers authorized to charge market-based rates that (i) were not interconnected with the jurisdictional facilities of any affiliated interstate natural gas pipeline and (ii) had no exclusive franchise area, no captive ratepayers, and no market power. The FERC found that Pine Prairie qualified for this exemption from the standards of conduct in January 2006 and Bluewater qualified for this exemption in October 2006.

In November 2006, the D.C. Circuit vacated the standards of conduct regulations with respect to natural gas pipelines and storage companies, and remanded the matter to the FERC. Following a notice of proposed rulemaking, in October 2008, the FERC

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issued revised Standards of Conduct for Transmission Providers (Standards of Conduct). The Standards of Conduct continue to exempt natural gas storage providers like Pine Prairie, Bluewater and Southern Pines. The FERC has since issued three Orders on Rehearing and Clarification in October and November 2009 and April 2010. However, one request for rehearing of the April 2010 order is pending with the FERC. Accordingly, there may be further modifications to the Standards of Conduct upon rehearing.

Natural Gas Price Transparency. In April 2007, the FERC issued a notice of proposed rulemaking (NOPR) regarding price transparency provisions of the NGA and the Energy Policy Act of 2005 (the EAct 2005). In the notice, the FERC proposed to revise its regulations to, among other things, 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. In December 2007, the FERC issued Order No. 704 implementing the annual reporting provisions of the NOPR with minimal changes to the original proposal. The order became effective in February 2008. The FERC issued two orders on rehearing in 2008, and following a technical conference in March 2010, the FERC issued an order clarifying the reporting requirements in April 2010. Pine Prairie, Bluewater and Southern Pines are subject to these annual reporting requirements.

In November 2008, the FERC issued Order No. 720 requiring interstate pipelines and certain non-interstate facilities to post certain daily capacity and volume information. The rule extends to storage facilities (such as Bluewater) that provide no-notice service. The rule has been appealed, but pending the results of that appeal, Bluewater will be subject to a requirement to post volumes with respect to no-notice service flows at each receipt and delivery point.

Energy Policy Act of 2005. Under the EAct 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. EAct 2005 also gives the FERC authority to impose civil penalties for violations of the NGA up to \$1,000,000 per day per violation for violations occurring after August 8, 2005. The anti-manipulation rule and enhanced civil penalty authority reflect an expansion of FERC's NGA enforcement authority.

Other Proposed Regulation. 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. Accordingly, we cannot provide assurances that the less stringent and pro-competition regulatory approach recently pursued by the FERC and Congress will continue.

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

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prohibits the disposal of certain hazardous wastes on land without prior treatment. RCRA also requires waste generators subject to land disposal restrictions to provide notification of pre-treatment requirements to disposal facilities receiving such 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 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.

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 determined that emissions of carbon dioxide, methane and other greenhouse gases, or GHGs, present an endangerment 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, the EPA has begun adopting and implementing regulations to restrict emissions of GHGs under existing provisions of the CAA. The EPA recently adopted two sets of rules regulating GHG emissions under the

CAA, one of which requires a reduction in emissions of GHGs from motor vehicles and the other of which regulates emissions of GHGs from certain large stationary sources, effective January 2, 2011. The EPA's rules relating to emissions of GHGs from large stationary sources of emissions are currently subject to a number of legal challenges, but the federal courts have thus far declined to issue any injunctions to prevent EPA from implementing, or requiring state environmental agencies to implement, the rules. The EPA has also adopted rules requiring the reporting of GHG emissions from specified large GHG emission sources in the United States, including petroleum refineries, on an annual basis beginning in 2011 for emissions occurring after January 1, 2010, as well as certain onshore oil and natural gas

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facilities, including underground natural gas storage facilities, on an annual basis beginning in 2012 for emissions occurring in 2011.

In addition, the United States Congress has from time to time considered adopting legislation to reduce emissions of GHGs and almost one-half of the states have already taken legal measures to reduce emissions of GHG gases primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. Most of these cap and trade programs work by requiring major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and gas processing plants, to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year in an effort to achieve the overall GHG emission reduction goal.

The adoption of legislation or regulatory programs to reduce emissions of GHGs could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances, or to comply with new regulatory or reporting requirements. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the natural gas we store. Consequently, legislation and regulatory programs to reduce emissions of GHGs could have an adverse effect on our business, financial condition and results of operations. Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climatic events. If any such effects were to occur, they could have an adverse effect on our financial condition and results of 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, and the Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006. 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.

Occupational Safety and Health

Our operations are subject to a number of federal and state laws and regulations, including the federal Occupational Safety and Health Act (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

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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 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 environmental 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 environmental 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 environmental 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, 2010, 53 full time employees of Plains All American GP LLC devoted substantially all of their time to carrying out our operations.

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

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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.

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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.

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 Securities Exchange Act of 1934, as amended (the Exchange Act), as soon as reasonably practicable after we electronically file the material with, or furnish it to, the Securities and Exchange Commission.

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 minimum quarterly distribution 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 minimum quarterly distribution. 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

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level of demand for the natural gas storage services we provide and the rates we are able to charge for such services;

regulatory action affecting the rates we can charge for the services we provide, the demand for natural gas, the supply of natural gas, 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.

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 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 671 Bcf. These projects, if developed

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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 store natural gas that is transported in interstate commerce, our natural gas storage facilities are subject to comprehensive regulation by the FERC under the NGA. Federal regulation under the NGA extends to a wide array of matters, including rates, terms of service, types of service, expansions and other matters.

The NGA requires that tariff rates for our interstate gas storage facilities be just and reasonable. In addition, under the NGA and applicable FERC regulations, we are prohibited from unduly preferring or unreasonably discriminating against any person with respect to rates or terms and conditions of service.

The rates and terms and conditions for interstate services provided by our facilities are set forth in a FERC-approved tariff for each facility which in each case currently permits us to charge market-based rates. Market-based rate authority allows us to negotiate rates with individual customers based on market demand. This right to charge market-based rates may be challenged by a party filing a complaint with FERC. Our market-based rate authorization may also be re-examined if we add substantial new storage capacity through expansion or acquisition and as a result obtain market power. Any successful complaint or protest against our rates could have an adverse impact on our revenues associated with providing storage services.

Should we fail to comply with all applicable FERC-administered statutes, rules, regulations and orders, we could be subject to substantial penalties and fines. Under the Energy Policy Act of 2005, or EPCA 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 EPCA 2005. See Items 1 and 2. Business and Properties Regulation.

Finally, new rules, 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, 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 authorizations to charge market-based rates are subject to the continued existence of certain conditions related to the competitive position of our facilities in their respective markets and, if those conditions change, the right to charge market-based rates could be terminated.

The rates we charge for storage services are regulated by FERC pursuant to its market-based rate policy, which allows regulated entities to charge rates different from, and in some cases, less than, those which would be permitted under traditional cost-of-service regulation. Our authorization to charge market-based rates is based on determinations by FERC that the facilities have no market power in their respective markets. The determination that storage facilities lack market power is subject to review and revision by FERC if there is a change in circumstances that could affect the ability of additional storage or interconnected pipeline facilities to exercise market power. Among the sorts of changes in circumstances that could raise market power concerns would be

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an expansion of capacity, acquisitions, or other changes in market dynamics. If the FERC were to conclude that a facility may have acquired and cannot mitigate market power, its rates could become subject to cost-of-service regulation.

If a facility's rates become subject to cost-of-service regulation, the maximum rates that may be charged for storage services would be established through FERC's ratemaking process, and the facility would no longer be able to charge a rate demanded by the market. Generally, cost-of-service based rates for interstate natural gas services are based on the cost of providing service including recovery of, and a reasonable return on, the entity's actual prudent historical cost investment for providing jurisdictional service. Key determinants in the ratemaking process are costs of providing service, allowed rate of return, and billing determinants, which are based upon storage volumes and contractual capacity commitment assumptions. Rate design and the allocation of costs underlying cost-of-service based rates must also be approved by FERC as part of each rate case. The resolution of these key determinants, particularly the allowed rate of return and billing determinants that would underlie the cost-of-service based rates through the FERC's ratemaking process, could adversely impact our profitability, and have adverse consequences on our cash flow and our ability to make distributions. Additionally, changes in generally applicable FERC ratemaking policies could also affect us.

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 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. If volatility and seasonality in the natural gas industry decrease, because of increased production capacity or otherwise, the demand for our services and the prices that we will be able to charge for those services may decline.

In addition to volatility and seasonality, an extended period of high gas prices would increase the cost of acquiring base gas and likely place upward pressure on the costs of associated expansion activities. An extended period of low natural gas prices could adversely impact storage values for some period of time until market conditions adjust. These commodity price impacts could have a negative impact on our business and financial results.

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, 2010, the weighted average remaining tenor of our existing portfolio of firm storage contracts is approximately 3.0 years at Pine Prairie, approximately 2.1 years at Bluewater and approximately 5.5 years at Southern Pines. For the year ended December 31, 2010, Iberdrola Renewables, Inc., Guardian Pipeline, LLC and Anadarko Energy Services accounted for approximately 13%, 9% and 8% of our revenues, respectively. The extension or replacement of existing contracts depends on a number of factors beyond our control.

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.

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 volume of storage services provided by us could have a material adverse effect on our business, financial condition, results of operation and ability to make distributions.

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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 current permitted expansion plans include the addition of 21 Bcf of working gas storage capacity at our Pine Prairie facility, 18 Bcf of which we expect to place into service in stages through mid-2012. In addition, in October of 2010, we submitted an application with the FERC requesting approval to construct 32 Bcf of additional capacity at Pine Prairie, an expansion application that will, if approved, increase Pine Prairie's permitted working gas capacity from 48 to 80 Bcf. We also plan to expand the working gas storage capacity of the Southern Pines facility to its permitted level of 40 Bcf. See Items 1 and 2. **Business and Properties** Recent Developments Acquisition of SG Resources Mississippi, LLC. In connection with these expansion efforts, 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 be able to increase the capacity of our Pine Prairie or Southern Pines facilities beyond our current expansion plans.

We have both the property rights and operational capacity necessary to expand both our Pine Prairie facility and our Southern Pines facility beyond their respective currently permitted capacities of 48 Bcf and 40 Bcf, respectively. As indicated above, in October of 2010, we submitted an application with the FERC requesting approval to construct 32 Bcf of additional capacity at Pine Prairie, an expansion application that will, if approved, increase Pine Prairie's permitted working gas capacity from 48 to 80 Bcf. In addition, we believe Pine Prairie can be expanded to a potential

of over 150 Bcf of total working gas storage capacity. Albeit to a lesser degree, we also have expansion capabilities beyond 40 Bcf at Southern Pines. See Items 1 and 2. Business and Properties Recent Developments. We may not be able to secure the financing or permits necessary to pursue such expansion and the necessary infrastructure modifications that would be needed to accommodate such expansion. Additionally, such expansion will be subject to market demand, the successful execution of any expansion projects and the availability of sufficient third-party

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interstate and intrastate pipelines receipt and deliverability capacity to accommodate the increased capacity. Any combination of these factors may prevent us from expanding our Pine Prairie or Southern Pines facilities beyond their current permitted capacity.

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

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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 and avoid a breach or increase our costs in doing so.

Our marketing activities could result in financial losses.

Without altering our basic commercial strategy of committing a high percentage of our storage capacity under multi-year firm storage contracts, during 2010 we formed a dedicated commercial marketing group in order to capture short-term market opportunities by utilizing a portion of our owned or leased storage capacity for our own account and engaging in related commercial marketing activities. Through these transactions, we will 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. While we intend to conduct these transactions within these pre-defined risk parameters, these policies will not eliminate all risks. For example, any event that disrupts our anticipated physical supply of or market for natural gas could expose us to significant costs or expenses in order to enable us to satisfy our obligations to store or deliver contracted natural gas volumes.

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 U.S. Environmental Protection Agency and analogous state agencies, have the power to enforce compliance with these laws and regulations and the permits issued under them, oftentimes requiring difficult and costly 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 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;

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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 on a per unit basis due to the following factors:

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 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

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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 and 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;

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

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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 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.

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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.

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

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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, 2010, we had \$25 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 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.

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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.

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.

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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.

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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 28, 2011, PAA holds 28,272,870 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

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- (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

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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.

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

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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.

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.

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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.

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

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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

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. See Items 1 and 2. Business and Properties Regulation Natural Gas Storage Regulation.

Item 4. (Removed and Reserved)

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 28, 2011, the closing market price for our common units was \$24.37 per unit and there were approximately 7,247 record holders and beneficial owners (held in street name). As of February 28, 2011, there were 59,184,450 common units outstanding.

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
	High	Low	(1)
2010			
4th Quarter	\$25.75	\$22.61	\$ 0.3450
3rd Quarter	\$26.65	\$22.61	\$ 0.3375
2nd Quarter (2) (3)	\$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.

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:

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

Date Declared	Date Paid or To Be Paid	Distributions Paid					Distributions per limited partner unit
		Common	Subordinated	General Partner	Incentive	2%	
January 12, 2011	February 14, 2011 ⁽¹⁾	\$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 4, 2011, for the period October 1, 2010 through December 31, 2010.

⁽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 2010, and we do not have any announced or existing plans to repurchase any of our common units.

Table of Contents**Item 6. Selected Financial Data**

	Predecessor			January 1, 2009	Successor September 3, 2009	Pro Forma (1)	Successor
	Year Ended December 31, 2006	Year Ended December 31, 2007	Year Ended December 31, 2008	through September 2, 2009	through December 31, 2009	Year Ended December 31, 2009	Year Ended December 31, 2010
(in thousands, except for per unit data and monthly operating metrics)							
Statement of operations data:							
Total revenues	\$ 30,831	\$ 36,945	\$ 49,177	\$ 46,929	\$ 25,251	\$ 72,180	\$ 100,287
Storage related costs	100	3,847	8,934	8,792	7,003	15,795	23,465
Operating costs (except those shown below)	3,658	3,947	4,059	4,820	3,257	8,077	7,242
Fuel expense	613	1,140	2,320	1,816	578	2,394	2,368
General and administrative expenses	3,402	3,755	3,874	3,562	4,083	8,885	15,965
Depreciation, depletion and amortization	3,986	4,520	6,245	8,054	3,578	11,341	14,119
Total costs and expenses	11,759	17,209	25,432	27,044	18,499	46,492	63,159
Operating income	19,072	19,736	23,745	19,885	6,752	25,688	37,128
Interest expense	(8,389)	(7,108)	(4,941)	(4,352)	(4,262)	(11,676)	(7,323)
Interest income and other income (expense), net	2,030	5,378	1,669	458	(2)	456	(18)
Income tax expense			(887)	(473)		(473)	
Net income	\$ 12,713	\$ 18,006	\$ 19,586	\$ 15,518	\$ 2,488	\$ 13,995	\$ 29,787
Calculation of Limited Partner Interest in Net Income: (2)							
Net income	n/a	n/a	n/a	n/a	n/a	n/a	\$ 24,359
Less general partner interest in net income	n/a	n/a	n/a	n/a	n/a	n/a	537
Limited partner interest in net income	n/a	n/a	n/a	n/a	n/a	n/a	\$ 23,822
Per unit data:							
Basic net income per limited partner unit(2)	n/a	n/a	n/a	n/a	n/a	n/a	\$ 0.54
Diluted net income per limited partner unit(2)	n/a	n/a	n/a	n/a	n/a	n/a	\$ 0.54
Declared distribution per limited partner unit(3)	n/a	n/a	n/a	n/a	n/a	n/a	\$ 0.345
Balance sheet data (at end of period):							
Total assets	\$ 518,092	\$ 674,765	\$ 811,436		\$ 900,407		\$ 998,728
Long-term debt	\$ 227,300	\$ 352,713	\$ 415,263		\$ 450,523		\$ 259,900
Total debt	\$ 227,300	\$ 355,163	\$ 417,713		\$ 450,523		\$ 259,900
Members /partners capital	\$ 264,109	\$ 294,717	\$ 363,229		\$ 432,744		\$ 723,390

Other financial data:

Adjusted EBITDA ⁽⁴⁾	\$ 27,395	\$ 29,663	\$ 31,001	\$ 28,701	\$ 12,165 ⁽⁵⁾	\$ 39,626	\$ 53,857
Distributable cash flow ⁽⁴⁾	\$ 19,006	\$ 22,156	\$ 25,577	\$ 23,965	\$ 7,200	\$ 26,863	\$ 44,962
Maintenance capital expenditures	\$	\$	\$ 377	\$ 384	\$ 320	\$ 704	\$ 438

Net cash provided by (used in) operating activities	\$ 13,973	\$ 22,343	\$ 21,818	\$ 22,603	\$ 15,265		\$ 44,361
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Net cash provided by (used in) investing activities	\$ (206,612)	\$ (177,280)	\$ (118,890)	\$ (58,561)	\$ (9,656)		\$ (103,580)
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Net cash provided by (used in) financing activities	\$ 158,771	\$ 145,743	\$ 122,344	\$ 23,636	\$ (22,813)		\$ 56,441
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Operating data:

Net revenue margin ⁽⁶⁾	\$ 30,731	\$ 33,098	\$ 40,243	\$ 38,137	\$ 18,248	\$ 56,385	\$ 76,822
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Other operating expenses / G&A / Other	(3,336)	(3,435)	(9,242)	(9,436)	(6,083)	(16,759)	(22,965)
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Adjusted EBITDA	\$ 27,395	\$ 29,663	\$ 31,001	\$ 28,701	\$ 12,165	\$ 39,626	\$ 53,857
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Average working storage capacity (Bcf) ⁽⁷⁾	24	26	27	36	40	38	47
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Monthly Operating Metrics (\$/Mcf)

Net revenue margin	\$ 0.11	\$ 0.11	\$ 0.12	\$ 0.13	\$ 0.11	\$ 0.12	\$ 0.14
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Operating expenses / G&A / Other	(0.01)	(0.01)	(0.03)	(0.03)	(0.03)	(0.03)	(0.04)
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Adjusted EBITDA	\$ 0.10	\$ 0.10	\$ 0.09	\$ 0.10	\$ 0.08	\$ 0.09	\$ 0.10
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- (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.
- (2) Reflective of general and limited partner interest in net income since closing of the Partnership's initial public offering. See Note 2 to our consolidated financial statements.
- (3) Excludes Series B subordinated units. See Note 2 to our consolidated financial statements.
- (4) For further discussion, see Non-GAAP and Segment Financial Measures.
- (5) The successor period 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.
- (6) Net revenue margin equals total revenues minus storage related costs.
- (7) Calculated as the sum of total owned 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 within 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, unrealized 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,

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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.

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

	Year Ended	Predecessor Year Ended	Year Ended	January 1	Successor September 3	Pro Forma ⁽¹⁾ Year Ended	Successor Year Ended
	December 31, 2006	December 31, 2007	December 31, 2008	September 2, 2009	December 31, 2009	December 31, 2009	December 31, 2010
				(in thousands)			
Adjusted EBITDA reconciliation							
Net income	\$ 12,713	\$ 18,006	\$ 19,586	\$ 15,518	\$ 2,488	\$ 13,995	\$ 29,787
Income tax expense			887	473		473	
Interest expense, net of amounts capitalized	8,389	7,108	4,941	4,352	4,262	11,676	7,323
Depreciation, depletion and amortization	3,986	4,520	6,245	8,054	3,578	11,341	14,119
Selected items impacting Adjusted EBITDA							
Equity compensation expense	515	553	(110)	304	1,467	1,771	2,747
Acquisition related costs							251
Mark-to-market on open derivative positions	1,792	(524)	(548)		370	370	(370)
Adjusted EBITDA	\$ 27,395	\$ 29,663	\$ 31,001	\$ 28,701	\$ 12,165	\$ 39,626	\$ 53,857
Distributable cash flow reconciliation							
Net income	\$ 12,713	\$ 18,006	\$ 19,586	\$ 15,518	\$ 2,488	\$ 13,995	\$ 29,787
Depreciation, depletion and amortization	3,986	4,520	6,245	8,054	3,578	11,341	14,119
Income tax expense			887	473		473	

Acquisition related costs								251
Maintenance capital expenditures			(377)	(384)	(320)	(704)		(438)
Other non cash items:								
Net, non cash equity compensation	515	154	(216)	304	1,084	1,388		1,613
Mark-to-market on open derivative positions	1,792	(524)	(548)		370	370		(370)
Distributable cash flow	\$ 19,006	\$ 22,156	\$ 25,577	\$ 23,965	\$ 7,200	\$ 26,863	\$ 44,962	

- (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

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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.

For periods prior to our initial public offering, the historical condensed 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 5 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 Spending and Significant Activities
Critical Accounting Policies and Estimates

Recent Accounting Pronouncements

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Outlook

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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, 2010, we owned and operated two natural gas storage facilities located in Louisiana and Michigan that have an aggregate working gas storage capacity of 50 Bcf and an aggregate peak injection and withdrawal capacity of 1.7 Bcf per day and 3.2 Bcf per day, respectively. In February 2011, we acquired the Southern Pines facility. See Items 1 and 2. **Business and Properties** Recent Developments Acquisition of SG Resources Mississippi, L.L.C. for further discussion of our February 2011 acquisition of the Southern Pines facility.

As of December 31, 2010, our operating assets included the Pine Prairie facility, which is a recently constructed, high-deliverability salt-cavern natural gas storage complex located in Evangeline Parish, Louisiana and the Bluewater facility, which is a depleted reservoir natural gas storage complex located approximately 50 miles from Detroit in St. Clair County, Michigan. Pine Prairie has a total current working gas storage capacity of 24 Bcf in three salt caverns and Bluewater has total working gas storage capacity of approximately 26 Bcf in two depleted reservoirs.

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Overview of Operating Results, Capital Spending and Significant Activities

Adjusted EBITDA for the year ended December 31, 2010 was approximately \$53.9 million, a 36% increase over Adjusted EBITDA of approximately \$39.6 million for the year ended December 31, 2009 on a pro forma basis. This increase was primarily the result of continued expansion of our Pine Prairie facility, including placing our third cavern into service during the second quarter of 2010 which provided an additional 10 Bcf of working gas capacity. See *Results of Operations* for further discussion and analysis of our operating results. Expansion capital expenditures for 2010 were approximately \$86.0 million. Such expenditures were principally associated with the ongoing development of our Pine Prairie facility.

In May 2010, the Partnership completed its initial public offering, issuing approximately 13.5 million common units to the public for net proceeds of approximately \$268.2 million. Distributions declared for the period from the date of our initial public offering through December 31, 2010 were \$0.8939 per distribution eligible limited partner unit.

In October 2010, we filed with FERC for expansion of our Pine Prairie facility. The filing contemplates construction of an additional 32 Bcf of working gas storage capacity, including two new 12 Bcf caverns and the expansion of existing permitted capacity by eight Bcf. Receipt of FERC approval of the proposed expansions would increase Pine Prairie's permitted capacity from 48 Bcf to 80 Bcf.

In February 2011, we completed the acquisition of SG Resources Mississippi, LLC (*SG Resources*) from SGR Holdings, L.L.C. for consideration of approximately \$746 million, which is subject to finalization of working capital and capital expenditure adjustments as defined in the purchase and sale agreement for this transaction. The primary asset of SG Resources is the Southern Pines Energy Center (*Southern Pines*), a FERC-regulated, salt-cavern natural gas storage facility located in Greene County, Mississippi. Southern Pines is permitted for 40 Bcf of working gas capacity from four storage caverns. See Items 1 and 2. *Business and Properties* *Recent Developments* *Acquisition of SG Resources Mississippi, L.L.C.*

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 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 estimated provision will be recognized. This provision will be adjusted as if the amount was recognized when the combination occurred if material. 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

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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 2010, 2009 or 2008.

Property, Plant 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, plant and equipment and revised our estimates in September 2009. See Note 2 to our consolidated financial statements.

We also evaluate our property, plant 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, plant 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.

We did not have any asset impairments in 2010, 2009 or 2008.

Accruals and Contingent Liabilities. We record accruals or liabilities including, but not limited to, insurance claims, asset retirement obligations, 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 Accruals. We accrue 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 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 10 to our consolidated financial statements for further discussion of our equity compensation plans.

Mark-to-Market Accrual. In situations where we are required to mark-to-market derivatives pursuant to FASB guidance, the estimates of derivative gains or losses at a particular period are unrealized and will most likely not reflect the realized derivative gain or loss upon settlement of the derivative. We reflect estimates of current valuations for these items based on our internal records and information from third parties. For any 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.

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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 or 2008 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.

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 Transactions. 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.

The following table includes our operating results for these periods (dollar amounts in thousands, except per Mcf amounts). 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 face of our consolidated financial statements to highlight the fact that the financial information for such periods has been prepared under a different basis of accounting.

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	Pro					Favorable/(Unfavorable)			
Successor	Forma	Successor	Predecessor		Variance				
Year	Year	September	January	Year	2010	Pro	Pro forma		
Ended	Ended	through	through	Ended	Forma	2009	2009		
December	December	December	September	December	\$	%	\$	%	
31, 2010	31, 2009	31, 2009	2, 2009	31, 2008					
(in thousands, except monthly operating metrics)									
Revenues									
Firm Storage Services									
Reservation fees	\$ 85,651	\$ 62,535	\$ 22,919	\$ 39,616	\$ 37,674	\$ 23,116	37%	\$ 24,861	63%
Cycling fees and fuel-in-kind	5,314	4,086	1,053	3,033	5,197	1,228	30%	(1,111)	-37%
Hub Services	6,190	4,625	1,637	2,988	1,417	1,565	34%	3,208	107%
Other	3,132	934	(358)	1,292	4,889	2,198	235%	(3,955)	-306%
Total revenue	100,287	72,180	25,251	46,929	49,177	28,107	39%	23,003	49%
								(6,861)	
Storage related costs	(23,465)	(15,795)	(7,003)	(8,792)	(8,934)	(7,670)	-49%		-78%
Other operating costs (except those shown below)	(7,242)	(8,077)	(3,257)	(4,820)	(4,059)	835	10%	(4,018)	-83%
Fuel expense	(2,368)	(2,394)	(578)	(1,816)	(2,320)	26	1%	(74)	-4%
General and administrative expenses	(15,965)	(8,885)	(4,083)	(3,562)	(3,874)	(7,080)	-80%	(5,011)	-141%
Interest income and other income (expense), net	(18)	456	(2)	458	1,669	(474)	-104%	(1,213)	-265%
Equity compensation expense	2,747	1,771	1,467	304	(110)				
Acquisition related costs	251								
Mark-to-market of open derivative positions	(370)	370	370		(548)				
Adjusted EBITDA	\$ 53,857	\$ 39,626	\$ 12,165	\$ 28,701	\$ 31,001	\$ 14,231	36%	\$ 8,625	30%
Reconciliation to net income									
Adjusted EBITDA	\$ 53,857	\$ 39,626	\$ 12,165	\$ 28,701	\$ 31,001	\$ 14,231	36%	\$ 8,625	30%
Depreciation, depletion and	(14,119)	(11,341)	(3,578)	(8,054)	(6,245)	(2,778)	-24%	(5,096)	-63%

amortization										
Interest expense, net of capitalized interest	(7,323)	(11,676)	(4,262)	(4,352)	(4,941)	4,353	37%	(6,735)	-155%	
Income tax expense		(473)		(473)	(887)	473	100%	414	88%	
Equity compensation expense	(2,747)	(1,771)	(1,467)	(304)	110					
Acquisition related costs	(251)									
Mark-to-market of open derivative positions	370	(370)	(370)		548					
Net income	\$ 29,787	\$ 13,995	\$ 2,488	\$ 15,518	\$ 19,586	\$ 15,792	113%	\$ (5,591)	-36%	

Operating Data:

Net revenue margin ⁽¹⁾	\$ 76,822	\$ 56,385	\$ 18,248	\$ 38,137	\$ 40,243	\$ 20,437	36%	\$ 16,142	42%	
Other operating expenses/G&A/Other	(22,965)	(16,759)	(6,083)	(9,436)	(9,242)	(6,206)	-37%	(7,517)	-80%	
Adjusted EBITDA	\$ 53,857	\$ 39,626	\$ 12,165	\$ 28,701	\$ 31,001	\$ 14,231	36%	\$ 8,625	30%	

Average working storage capacity(Bcf)	47.0	38.0	40.0	36.0	27.0	9.0	24%	11.0	31%	
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Monthly Operating Metrics(\$/Mcf)

Net Revenue Margin	\$ 0.14	\$ 0.12	\$ 0.11	\$ 0.13	\$ 0.12	\$ 0.02	17%	\$	%	
Operating expenses / G&A / Other	(0.04)	(0.03)	(0.03)	(0.03)	(0.03)	(0.01)	33%		%	
Adjusted EBITDA	\$ 0.10	\$ 0.09	\$ 0.08	\$ 0.10	\$ 0.09	\$ 0.01	11%	\$	%	

(1) Net revenue margin equals total revenues minus storage related costs

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.

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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.

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

Revenues, Volumes and Storage 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 in April 2009 and April 2010, respectively. Additionally, total revenues and storage related costs increased due to additional leasing of third party storage and transportation assets 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 in April 2009 and April 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 volume of cycling activities as a result of a robust market supply of natural gas.

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.

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:

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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. An increase in fuel volumes used was approximately offset by lower average fuel prices. Our decrease in fuel volumes used was primarily driven by operational improvements in managing customer movements.

General and administrative expenses General and administrative expenses increased in the 2010 period as compared to the 2009 pro forma period. The 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. General and administrative expense for the 2010 period reflects 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, during the 2010 period we recognized 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.

Interest income and other income (expense), net Interest income and other income (expense), net for the 2009 pro forma period was comprised primarily of interest income and ineffectiveness associated with an interest rate swap agreement. The reduction of interest income and other income (expense), net 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 now our 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.

Pro forma year ended December 31, 2009 and year ended December 31, 2008

Revenues, Volumes and Storage Related Costs. As noted in the table above, our total revenue and storage related costs increased for the year ended December 31, 2009 on a pro forma basis (2009 pro forma period) as

compared to the year ended December 31, 2008 (the 2008 period). This increase primarily resulted from our second Pine Prairie facility cavern being placed into operation in April 2009. Significant additional variances related to these periods are discussed below:

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Firm storage reservation fees Firm storage reservation fee revenues increased for the 2009 pro forma period as compared to the 2008 period, primarily due to an additional 8 Bcf of capacity being placed into service at Pine Prairie during 2009, along with a full year of operations for our initial 5 Bcf of capacity at Pine Prairie. Our Pine Prairie facility generated approximately \$19.4 million of incremental firm storage services revenues during the 2009 pro forma period. Revenues from firm storage reservation fees were also positively impacted by loan transactions and third-party transportation activities together with increases in storage leased from third parties for the 2009 pro forma period when compared to the 2008 period. See Storage related costs below.

Firm storage cycling fees and fuel-in-kind Firm storage cycling fees and fuel-in-kind revenues decreased in the 2009 pro forma period as compared to the 2008 period primarily due to a decrease in the period over period average natural gas price of approximately 53% in the 2009 pro forma period, which was partially offset by increased volumes collected primarily due to an additional 8 Bcf of capacity being placed into service at our Pine Prairie facility.

Hub services Hub services increased approximately \$3.2 million in the 2009 pro forma period as compared to the 2008 period. This increase was primarily related to increased wheeling and balancing services through the utilization of transportation capacity during the 2009 pro forma period. See Storage related costs below.

Other Other revenue for each of the periods was comprised primarily of crude oil sales. The decrease in the 2009 pro forma period as compared to the 2008 period was primarily related to lower average prices realized in the 2009 pro forma period. Additionally, other revenue during the 2008 period reflects a realized gain of approximately \$1.1 million on a natural gas storage-related futures derivative position. Other revenue for the 2009 pro forma period includes an unrealized loss of approximately \$0.4 million on a natural gas storage related futures derivative position.

Storage related costs We increased the amount of storage and transportation capacity leased from third parties in the 2009 pro forma period compared to the 2008 period. In addition, we experienced higher costs as a result of increased loan transactions in the 2009 pro forma period compared to the 2008 period. See Firm storage reservation fees above.

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

Operating costs Field operating costs increased in the 2009 pro forma period compared to the 2008 period. This increase is primarily related to our continued expansion of the Pine Prairie facility and related growth in personnel costs.

Fuel expense Fuel expense was relatively flat in the 2009 pro forma period compared to the 2008 period as an increase in volumes used was largely offset by a decrease in the average price of natural gas.

General and administrative expenses General and administrative expenses increased in the 2009 pro forma period compared to the 2008 period. This increase was driven by increased costs primarily related to the continued expansion of our business and growth in personnel costs, including an increase in costs allocated to us from PAA as a result of PAA personnel devoting additional time and effort to our operations.

Depreciation, depletion and amortization Depreciation, depletion and amortization expense increased in the 2009 pro forma period compared to the 2008 period. This increase was driven primarily by an increased amount of depreciable assets resulting from our internal growth projects (including our second

Pine Prairie facility cavern) along with an increase in the basis of property and equipment as a result of fair value adjustments recorded in connection with the PAA Ownership Transaction. These increases were partially offset by adjustments to the estimated useful lives of our property and equipment in conjunction with the PAA Ownership Transaction which lengthened the estimated useful lives of most of our more significant components of property and equipment. Depreciation, depletion and amortization expense includes amortization of debt issue costs and intangibles of \$2.6 million and \$1.4 million in the 2009 pro forma period and 2008 period, respectively.

Interest expense, net of capitalized interest Interest expense increased in the 2009 pro forma period as compared to the 2008 period. This increase was principally due to an increase in our outstanding debt balance as a result of the intercompany note entered into with PAA in conjunction with the PAA Ownership Transaction, which bore interest at a higher rate than debt previously outstanding under our predecessor's credit facilities.

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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 now our unitholders. Our income tax expense consists principally of state income taxes calculated on an apportionment basis. The income tax expense is lower in the 2009 pro forma period when compared to the 2008 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.

Interest Income and Other Income (Expense), Net Interest income and other income (expense), net is comprised primarily of interest income and decreased for the 2009 pro forma period compared to the 2008 period primarily due to a decrease in our average cash balances. The year over year decreases in interest income was also impacted by lower average interest rates for the 2009 pro forma period as compared to the 2008 period.

Outlook

Following a multi-year period of favorable market conditions for natural gas storage providers, overall market conditions for both hub services and firm storage services softened throughout 2010. Factors we believe contributed to this deterioration include reduced spread and basis differentials and associated volatility, which we believe were impacted by a combination of factors, including weather patterns, shale gas production and pipeline infrastructure additions. Market conditions weakened progressively in the second half of 2010 with seasonal spreads, as reflected by the October 2010 to January 2011 NYMEX spread, decreasing to a five-year low of \$0.46 per dekatherm during the third quarter of 2010.

We believe certain of the supply and demand factors contributing to the weakness are self-correcting over time and that the long-term demand for storage is positive. Additionally, we believe our asset base, contract profile, financial position and low risk, economically attractive expansion projects will enable us to continue to grow our cash flows for the next several years even if such conditions persist, albeit at lower levels of growth than would have been experienced in a strong market environment. We also believe we are reasonably well positioned to pursue and consummate additional acquisitions.

However, if weak gas storage market conditions persist, in addition to adversely affecting hub services activities, they may adversely impact the lease rates our customers are willing to pay for firm storage services with respect to new capacity under construction as well as renewals of existing capacity upon expirations of existing term leases. Accordingly, although a significant portion of our existing capacity is underpinned by multi-year firm storage contracts, we will not be unaffected by adverse overall market conditions. Additionally, we can provide no assurance that our operating and financial results will not be adversely impacted by such conditions, or that our acquisition and organic growth efforts will be successful.

Liquidity and Capital Resources

Overview

Our primary cash requirements include, but are not limited to (i) ordinary course of business uses, such as the payment of amounts related to storage costs incurred and other operating and general and administrative expenses, interest payments on our outstanding debt and distributions to our owners, (ii) maintenance and expansion capital expenditures, including purchases of base gas, (iii) acquisitions of assets or businesses and (iv) repayment of principal on our long-term debt. We generally expect to fund our short-term cash requirements through our primary sources of liquidity, which consist of our cash flow generated from operations as well as borrowings under our credit facility. In addition, we generally expect to fund our long-term needs, such as those resulting from expansion activities or acquisitions, through a variety of sources (either separately or in combination), which may include operating cash flows, borrowings under our credit facilities, and/or proceeds from the issuance of additional equity or debt securities.

In conjunction with our initial public offering, we entered into a three-year, \$400 million senior unsecured revolving credit facility. This credit facility, which bears interest based on LIBOR plus an applicable margin determined based on funded debt-to-EBITDA levels, may be expanded to \$600 million with approval of the administrative agent for the credit facility. This credit facility restricts, among other things, the Partnership's ability to make distributions of available cash to unitholders if any default or event of default, as defined in the agreement,

exists or would result therefrom. In addition, the credit facility contains restrictive covenants, including those that restrict our ability to incur additional indebtedness, engage in transactions with affiliates, grant (or permit to exist) liens or enter into certain restricted contracts, 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. Also, the credit facility contains certain financial covenants requiring us to maintain certain financial ratios related to our consolidated EBITDA,

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consolidated interest charges and consolidated funded indebtedness, as such terms are defined in the credit agreement. At December 31, 2010, we had \$260 million outstanding under this facility. The extent to which we can borrow against the remaining \$140 million depends on our ability to maintain various financial ratios, including a debt-to-EBITDA coverage ratio of less than 4.75 to 1.00 on outstanding debt (5.50 to 1.00 on all outstanding debt during an acquisition period) and an interest-to-EBITDA coverage ratio of no less than 3.00 to 1.00 (in each case, as such terms are defined in the credit agreement). As of December 31, 2010, we were in compliance with the covenants, including the financial ratios, contained in our credit agreement. Based on the most restrictive covenant, at December 31, 2010 our total available debt would be limited to approximately \$284 million of the \$400 million. Notably, the restriction on debt incurrence does not limit our ability to incur hedged inventory debt. Also, the formula for determining EBITDA in the context of the financial ratios allows for inclusion of pro forma EBITDA for certain capital investments we may make in the future, including for acquisitions and certain capital expenditures related to our Pine Prairie expansion.

PAA may elect, but is not obligated, to provide financial support to us under certain circumstances, such as in connection with an acquisition or expansion capital project. Our partnership agreement contains provisions designed to facilitate PAA's ability to provide us with financial support while reducing concerns regarding conflicts of interest by defining certain potential financing transactions between PAA and us as fair to our unitholders. As further defined in our partnership agreement, potential PAA financial support can include, but is not limited to, our issuance of common units to PAA, our borrowing of funds from PAA or guaranties or trade credit support to support the ongoing operations of us or our subsidiaries. We have no obligation to seek financing or support from PAA or to accept such financing or support if offered to us.

Congress recently enacted the Dodd-Frank Wall Street Reform and Consumer Protection Act (the Dodd-Frank Act), which includes provisions regarding the use of derivative financial instruments. The scope and applicability of these provisions is not entirely clear and regulations implementing certain aspects of the Dodd-Frank Act have not yet been issued. We are currently reviewing the provisions of this legislation and its potential impact on our business, and will continue to monitor the final rules and regulations as they develop.

Our current sources of liquidity include:

cash generated from operations;

borrowings under our credit facility;

issuances of additional partnership units; and

debt offerings.

We believe that cash generated from these sources will be sufficient to meet our short-term working capital requirements, long-term capital expenditure requirements, and quarterly cash distributions to unitholders.

To maintain our targeted credit profile, we generally intend to fund approximately 60% of the capital required for expansion projects beyond the projects currently under development, as well as future acquisitions, with equity and cash flow in excess of distributions.

For a discussion of the impact that the price of natural gas might have on our operations and liquidity and capital resources, see Item 7a. Quantitative and Qualitative Disclosures About Market Risk.

Working Capital. Working capital, defined as the amount by which current assets exceed current liabilities, is an indication of our liquidity and potential need for short-term funding. Our working capital requirements are driven primarily by changes in accounts receivable and accounts payable. These changes are primarily affected by factors such as credit extended to, and the timing of collections from, our customers and our level of spending for maintenance and expansion activity. As of December 31, 2010 we had working capital of \$1 million (excluding \$20 million in restricted cash).

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Historical cash flow information. The following table reflects cash flows for the applicable periods (in thousands):

	Successor		Predecessor	
	Year	September	January	Year Ended
	Ended	3,	1,	December
	December	2009	2009	December
	31,	through	through	31,
	2010	December	September	2008
	31,	31,	2,	31,
	2010	2009	2009	2008
Net cash provided by (used in):				
Operating activities	\$ 44,361	\$ 15,265	\$ 22,603	\$ 21,818
Investing activities	(103,580)	(9,656)	(58,561)	(118,890)
Financing activities	56,441	(22,813)	23,636	122,344
Net increase/(decrease) in cash	\$ (2,778)	\$ (17,204)	\$ (12,322)	\$ 25,272
Adjusted EBITDA	\$ 53,857	\$ 12,165	\$ 28,701	\$ 31,001

Operating Activities. The primary drivers of cash flow from our operations are (i) the collection of amounts related to the storage of natural gas, and (ii) the payment of amounts related to expenses, principally storage and transportation related costs, field operating costs and general and administrative expenses.

Investing Activities. Our investing activities for each of the periods listed above primarily relate to the continued expansion of our Pine Prairie facility and the acquisition of the related base gas required to operate the facility.

Financing Activities. Our financing activities for each of the periods listed above primarily relate to the funding of the investing activities discussed above. To fund these expenditures we made borrowings under our available credit facilities and received capital contributions from our equity owners.

Distributions to our unitholders and general partner. Our partnership agreement requires us to distribute all of our available cash quarterly. Generally, our available cash is our cash on hand at the end of the quarter after the payment of our expenses and the establishment of cash reserves and cash on hand resulting from borrowings, including working capital borrowings, made after the end of the quarter.

Capital Requirements. We currently forecast capital expansion expenditures for 2011 of approximately \$103 million (including capitalized interest), primarily related to the ongoing expansion of our Pine Prairie facility and our recently acquired Southern Pines facility and the related base gas required to operate the facilities. We expect to fund our capital expenditures with cash generated from operations and borrowings under our credit facility. Additionally, we are forecasting approximately \$0.8 million of maintenance capital expenditures in 2011.

Acquisitions. In February 2011, we completed the acquisition of SG Resources Mississippi, L.L.C., the owner of the Southern Pines Energy Center natural gas storage facility, for total consideration of approximately \$746 million, subject to certain post-closing adjustments.

Borrowings and Equity Offerings. To fund our February 2011 acquisition of SG Resources Mississippi, L.L.C. we issued an additional 27.6 million common units for total proceeds of approximately \$600 million, including PAA's proportionate general partner contribution, and borrowed approximately \$200 million from PAA.

See Items 1 and 2. **Business and Properties** Recent Developments Acquisition of SG Resources Mississippi, L.L.C. for further discussion of our February 2011 Southern Pines Acquisition and the related financing transactions.

Contingencies

For a discussion of contingencies that may impact us, see Note 11 to our consolidated financial statements.

Table of Contents**Commitments**

Contractual Obligations. In the ordinary course of doing business, we lease storage and transportation capacity from third parties, incur debt and interest payments and enter into purchase commitments in conjunction with our operations and our capital expansion program.

The following table includes our best estimate of the amount and timing of the payments due under our contractual obligations as of December 31, 2010 (in millions):

	Total	2011	2012	2013	2014	2015	Thereafter
Long-term debt, interest and fees ⁽¹⁾	\$ 280.8	\$ 8.9	\$ 8.9	\$ 263.0	\$	\$	\$
Leases storage, transportation, other	37.7	14.2	10.7	6.2	4.5	2.0	0.1
Purchase obligations	35.3	18.1	1.9	1.9	1.8	1.8	9.8
Other long-term liabilities	1.2	0.7	0.3		0.1	0.1	
Total	\$ 355.0	\$ 41.9	\$ 21.8	\$ 271.1	\$ 6.4	\$ 3.9	\$ 9.9

(1) Includes interest payments and commitment fees on our senior unsecured revolving credit facility.

Letters of Credit. In connection with our use of certain leased storage and transportation assets, we have periodically provided certain suppliers with irrevocable standby letters of credit to secure our obligations for the purchase of these services. Our liabilities with respect to these purchase obligations are recorded in accounts payable on our consolidated balance sheet in the month the services are provided. In certain instances, parental guarantees were provided by PAA in lieu of letters of credit. At December 31, 2010, we no longer have outstanding parental guarantees or outstanding letters of credit. Our \$400 million senior unsecured revolving credit facility provides us with the ability to issue letters of credit.

Off-balance Sheet Arrangements

We do not have any off-balance sheet arrangements as defined by Item 303 of Regulation S-K.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

From time to time, we may use derivative instruments to (i) manage our exposure to interest rates or natural gas prices associated with future natural gas purchases and sales and (ii) economically hedge the intrinsic value of our natural gas storage facilities. Our policy is to use derivative instruments only for non-trading risk management purposes. We may use various derivative instruments to manage such risks. Our risk management policies and procedures are designed to help ensure that our hedging activities address our risks by monitoring NYMEX, IntercontinentalExchange (ICE) and over-the-counter positions, as well as physical volumes, locations, delivery schedules and storage capacity. We have a risk management function that has direct responsibility and authority for our risk policies, related controls around commercial activities and procedures and certain aspects of corporate risk management. Our risk management function also approves all new risk management strategies through a formal process. The following discussion addresses each category of risk.

Commodity Price Risk

Storage Activities. 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. Except for the base gas we purchase and use in our facilities, which we consider to be a long-term asset, and volume and pricing variations related to small volumes of fuel-in-kind natural gas that we are entitled to retain from our customers as compensation for our fuel costs, our current business model is designed to minimize our exposure to fluctuations in the outright price of natural gas. As a result, absent other market factors that could adversely impact our operations, changes in the price of natural gas are not anticipated to materially impact our operations.

With respect to base gas, we typically use derivative instruments to hedge all or some portion of our anticipated base gas purchases. In addition, we periodically sell any fuel-in-kind volumes in excess of actual volumes needed for our facilities, and we may also purchase fuel in excess of our fuel-in-kind volumes to the extent such volumes are

needed to operate our facilities.

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Crude Oil Sales. We generate revenue through the sale of crude oil and liquids incrementally produced from our Bluewater facility and, accordingly, are exposed to commodity price fluctuations on the volumes of crude oil and liquids produced and sold from our Bluewater facility. We have not historically attempted to hedge the value of such sales.

Commercial Activities. During 2010, we established a dedicated commercial marketing group that intends to capture short-term market opportunities by utilizing a portion of our owned or leased storage capacity for our own account and engaging in related commercial marketing activities. We conduct these commercial activities within pre-defined risk parameters, and our general policy is to (i) purchase natural gas only in situations where we have a market for such gas, (ii) 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 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.

Revenues generated from these activities will be subject to commodity price risk, which has been volatile and unpredictable in the past. While we expect this volatility to continue in the future, we consider our exposure to commodity price risk not to be material as our risk procedures require that we maintain a balanced position as noted above. Our commercial marketing group entered into its initial physical and financial transactions during the fourth quarter of 2010. Such activity was not material to our consolidated financial position, results of operations or cash flows.

Our commodity derivatives at December 31, 2010 represented a net asset of \$0.1 million; a 10% decrease in natural gas prices would result in an unrealized loss of \$0.5 million.

Interest Rate Risk

Our \$400 million senior unsecured revolving credit facility bears interest based on LIBOR plus an applicable margin, which exposes us to risk associated with changes in market interest rates. Although we may enter into interest rate swaps to fix the interest rate on all or a portion of the borrowings under our credit facility in the future, we have not yet entered into any such arrangements. If we fail to do so, to the extent the interest rate on borrowings under our credit facility increases or decreases by 1%, interest on amounts outstanding will increase or decrease, respectively, by approximately \$2.6 million per year.

Item 8. Financial Statements and Supplementary Data

See Index to the Consolidated Financial Statements on page F-1.

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

None.

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

We maintain written disclosure controls and procedures, which we refer to as our DCP. Our DCP is designed to ensure that (i) information required to be disclosed by us in the reports that we file under the Exchange Act is recorded, processed, summarized and reported, within the time periods specified in the SEC's rules and forms; and (ii) such information is accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, to allow for timely decisions regarding required disclosure.

Applicable SEC rules require an evaluation of the effectiveness of the design and operation of our DCP. Management, under the supervision and with the participation of our Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of the design and operation of our DCP as of the end of the period covered by this report, and has found our DCP to be effective in providing reasonable assurance of the timely recording, processing, summarization and reporting of information, and in accumulation and communication of information to management to allow for timely decisions with regard to required disclosure.

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Internal Control over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting.

Internal control over financial reporting is a process designed by, or under the supervision of, our Chief Executive Officer and our Chief Financial Officer, and effected by our Board of Directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP. Our management, including our Chief Executive Officer and our Chief Financial Officer, has evaluated the effectiveness of our internal control over financial reporting as of December 31, 2010. See Management's Report on Internal Control Over Financial Reporting on page F-2.

Although we have made various enhancements to our controls, there have been no changes in our internal control over financial reporting during the period covered by this report that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Certifications

The certifications of our Chief Executive Officer and Chief Financial Officer pursuant to Exchange Act rules 13a-14(a) and 15d-14(a) are filed with this report as Exhibits 31.1 and 31.2. The certifications of our Chief Executive Officer and Chief Financial Officer pursuant to 18 U.S.C. 1350 are furnished with this report as Exhibits 32.1 and 32.2.

Item 9B. Other Information

There was no information that was required to be disclosed in a report on Form 8-K during the fourth quarter of 2010 that has not previously been reported.

Table of Contents**PART III****Item 10. *Directors and Executive Officers of Our General Partner and Corporate Governance*
Partnership Management and Governance**

Our general partner manages our operations and activities. The directors of our general partner oversee our operations. Unitholders are not entitled to elect our general partner or the directors of our general partner and do not participate in the management of our operations. Our partnership agreement limits any fiduciary duties our general partner might owe to our unitholders. As a general partner, our general partner is liable for all of our debts (to the extent not paid from our assets), except for indebtedness or other obligations that are made specifically non-recourse to it. Our general partner has the discretion to incur indebtedness or other obligations on our behalf on a non-recourse basis to the general partner and we expect that it will do so.

We are majority owned and controlled by PAA and our assets, liabilities and results of operations are consolidated in PAA's financial statements. During 2010, our contribution to adjusted EBITDA represented less than 5% of PAA's consolidated adjusted EBITDA. The officers of our general partner are employed by PAA's general partner and manage the day-to-day affairs of our business. Certain of our officers devote substantially all of their time to managing our business, while other officers have responsibilities for both us and PAA and devote the majority of their time to PAA's other business activities. We also utilize a significant number of employees of PAA's general partner to operate our business and provide us with general and administrative services.

We have entered into an omnibus agreement with PAA and certain of its affiliates, pursuant to which we agreed upon 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. The omnibus agreement does not increase or decrease our general partner's fiduciary duties to us under our partnership agreement. See Item 13. *Certain Relationships and Related Transactions, and Director Independence* for additional information regarding the omnibus agreement.

PAA is the sole member of our general partner and has the right to elect all seven members to the board of directors of our general partner. At least three of the members of our general partner's board of directors must be independent (as defined in applicable NYSE and SEC rules) and eligible to serve on the audit committee. In evaluating director candidates, PAA will assess whether a candidate possesses the integrity, judgment, knowledge, experience, skills and expertise that are commensurate with the board's responsibilities of managing and directing the affairs and business of the partnership, including, when applicable, enhancement of the ability of committees of the board to fulfill their duties.

Board Leadership Structure and Role in Risk Oversight

The board has no policy with respect to the separation of the offices of chairman and CEO. Currently, both positions are held by the CEO of PAA, the indirect general partner and majority equity holder in us. We do not have a lead independent director. Directors of our general partner are designated or elected by its sole member, PAA. Accordingly, unlike holders of common stock in a corporation, our unitholders have only limited voting rights on matters affecting our business or governance, subject in all cases to any specific unitholder rights contained in our partnership agreement. PAA has determined that the combined offices of Chairman and CEO represent an efficient and effective arrangement and that our leadership structure is appropriate in light of our ownership structure.

The management of enterprise-level risk may be defined as the process of identification, management and monitoring of events that present opportunities and risks with respect to creation of value for our unitholders. The board has delegated to management the primary responsibility for enterprise-level risk management, while the board has retained responsibility for oversight of management in that regard. Management will offer an enterprise-level risk assessment to the Board at least once every year.

Non-Management Executive Sessions and Shareholder Communications

NYSE listing standards require regular executive sessions of the non-management directors of a listed company, and an executive session for independent directors at least once a year. Under the NYSE definition, only the members of our Audit

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Committee qualify as non-management. As part of their regular quarterly meetings, our Audit Committee routinely holds discussions with no other directors or members of management present. The board also routinely holds executive sessions that exclude those directors and officers who devote substantially all of their time to managing our business. Our non-management directors and those directors who are also officers, but who devote the majority of their time to PAA's other business activities, attend these sessions. Effective in 2011, the chairmanship of non-management executive sessions of the board will rotate among the three non-management directors, sequenced alphabetically by last name.

Interested parties can communicate directly with non-management directors by mail in care of the Vice President Legal and Business Development or in care of the Managing Director of Internal Audit at PAA Natural Gas Storage, L.P., 333 Clay Street, Suite 1500, Houston, Texas 77002. Such communications should specify the intended recipient or recipients. Commercial solicitations or communications will not be forwarded.

Independence Determination and Audit Committee

Because we are a limited partnership, the listing standards of the NYSE do not require that we or our general partner have a majority of independent directors. We are, however, required to have an audit committee of at least three members, and all of its members are required to be independent as defined by the NYSE.

Pursuant to the NYSE listing standards, a director will be considered independent if the board determines that he or she does not have a material relationship with our general partner or us (either directly or indirectly as a partner, unitholder or officer of an organization that has a material relationship with our general partner or us) and otherwise meets the board's stated criteria for independence. The NYSE listing standards specify the criteria by which the independence of directors will be determined, including guidelines for directors and their immediate family members with respect to employment or affiliation with us or with our independent public accountants.

We have an audit committee that reviews our external financial reporting, engages our independent auditors, and reviews the adequacy of our internal accounting controls. The charter of our audit committee is available on our website. See Meetings and Other Information for information on how to access or obtain copies of this charter. The board of directors has determined that each member of our audit committee (Messrs. Burk, Shackouls and Smith) is independent under applicable NYSE rules and that Messrs. Burk and Smith are each an Audit Committee Financial Expert, as that term is defined in Item 407 of Regulation S-K.

In determining the independence of the members of our audit committee, the board of directors considered the relationships described below:

Victor Burk, chairman of our audit committee, is a managing director of Alvarez and Marsal, Inc., a business consulting firm that provides services from time to time to PAA and its affiliates, but not to PNG. Mr. Burk does not participate financially in the fees paid by PAA to Alvarez and Marsal. The board of directors of our general partner has determined that this relationship does not compromise the independence of Mr. Burk.

Bobby S. Shackouls, a member of our audit committee, is a director of ConocoPhillips, with whom PAA does a substantial amount of business. Mr. Shackouls is not an officer of ConocoPhillips and does not participate in operational decision making. The board of directors of our general partner has determined that this relationship does not compromise the independence of Mr. Shackouls. In February 2011, ConocoPhillips announced that Mr. Shackouls did not intend to stand for re-election to the ConocoPhillips board at the end of his term in May 2011.

Arthur L. Smith, a member of our audit committee, has no relationship with us or our general partner, other than as a director. Mr. Smith served on the board of directors of the general partner of PAA from February 1999 through December 2010.

For additional information regarding the experience and qualifications of our directors, see the biographical descriptions under Directors, Executive Officers and Other Officers of our General Partner below.

Other Committees

Applicable NYSE listing standards do not require that we or our general partner have a compensation or nominating committee. Our general partner's board of directors performs the functions of a compensation committee and administers our Long Term Incentive Plan and other equity and executive compensation plans. The board of directors has the sole authority to retain any

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compensation consultants to be used to assist the board, but did not retain any consultants in 2010. Similarly, the board of directors has not delegated any of its authority to subcommittees. The board of directors has delegated limited authority to the CEO to administer our Long-Term Incentive Plan with respect to employees other than executive officers.

Our partnership agreement provides for the establishment or activation of a conflicts committee, as circumstances warrant, to review conflicts of interest between us and our general partner or between us and PAA or its affiliates. Such a committee would consist of a minimum of two members, none of whom can be (i) an officer or employee of our general partner, (ii) a holder of any ownership interest in us, our subsidiaries, our general partner or its affiliates (other than (a) our common units or (b) other awards granted to such director under our LTIP) or (iii) an officer, director or employee of any affiliate of our general partner or any associate of such affiliate, and each of whom must meet the independence standards for service on an audit committee established by the NYSE and the SEC. A director will not be precluded from serving on such committee due to the ownership of common units of PAA or other indirect interests of our general partner unless the board of directors of our general partner determines, after taking into account the totality of the specific circumstances involving such director, that such ownership will likely have an adverse impact on the ability of such director to act in an independent manner with respect to the matter submitted to the conflicts committee. Any matters approved by the conflicts committee will be conclusively deemed to be fair and reasonable to us, approved by all of our partners, and not a breach by our general partner of any duties owed to us or our unitholders.

Meetings and Other Information

Since the date of our initial public offering through December 31, 2010, our board of directors had five meetings and our audit committee had five meetings. None of our directors attended fewer than 75% of the aggregate number of meetings of the board of directors and committees of the board on which the director served.

As discussed above, the corporate governance of our general partner is, in effect, the corporate governance of our partnership and directors of our general partner are designated or elected by the sole member of our general partner, PAA. Accordingly, unlike holders of common stock in a corporation, our unitholders have only limited voting rights on matters affecting our business or governance, subject in all cases to any specific unitholder rights contained in our partnership agreement. As a result, we do not hold annual meetings of unitholders.

Our Audit Committee Charter and Governance Guidelines, as well as our Code of Business Conduct and our Code of Ethics for Senior Financial Officers, which apply to our principal executive officer, principal financial officer and principal accounting officer, are available on our Internet website at <http://www.pnglp.com>. Print versions of the foregoing are available to any person without charge, upon request by writing to our Secretary, PAA Natural Gas Storage, L.P., 333 Clay Street, Suite 1500, Houston, Texas 77002. We intend to disclose any amendment to or waiver of the Code of Ethics for Senior Financial Officers and any waiver of our Code of Business Conduct on behalf of an executive officer or director either on our Internet website or in an 8-K filing. Our first annual CEO certification as required by Section 303A.12(a) of the NYSE's Listed Company Manual must be submitted to the NYSE within 30 days of filing our 2010 Annual Report on Form 10-K.

Audit Committee Report

The audit committee of our general partner oversees the Partnership's financial reporting process on behalf of the board of directors. Management has the primary responsibility for the financial statements and the reporting process including the systems of internal controls.

In fulfilling its oversight responsibilities, the audit committee reviewed and discussed with management the audited financial statements contained in this Annual Report on Form 10-K.

The Partnership's independent registered public accounting firm, PricewaterhouseCoopers LLP, is responsible for expressing an opinion on the conformity of the audited financial statements with accounting principles generally accepted in the United States of America. The audit committee reviewed with PricewaterhouseCoopers LLP the firm's judgment as to the quality, not just the acceptability, of the Partnership's accounting principles and such other matters as are required to be discussed with the audit committee under generally accepted auditing standards.

The audit committee discussed with PricewaterhouseCoopers LLP the matters required to be discussed by Statement of Auditing Standards No. 61, as amended, as adopted by the Public Company Accounting Oversight

Board. The committee received written disclosures and the letter from PricewaterhouseCoopers LLP required by applicable requirements of the Public Company

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Accounting Oversight Board regarding PricewaterhouseCoopers LLP's communications with the audit committee concerning independence, and has discussed with PricewaterhouseCoopers LLP its independence from management and the Partnership.

Based on the reviews and discussions referred to above, the audit committee recommended to the board of directors that the audited financial statements be included in the Annual Report on Form 10-K for the year ended December 31, 2010 for filing with the SEC.

Victor Burk, *Chairman*

Bobby S. Shackouls

Arthur L. Smith

Directors, Executive Officers and Other Officers of Our General Partner

The following table sets forth certain information with respect to the executive officers, directors, and certain other officers and key employees of our general partner. Directors are appointed for a term of one year and hold office until their successors have been elected or qualified or until the earlier of their death, resignation, removal or disqualification. Officers serve at the discretion of the board. There are no family relationships among any of our directors or executive officers. Some of our directors and executive officers also serve as directors or executive officers of PAA.

Name	Age (as of 12/31/2010)	Position with Our General Partner
Greg L. Armstrong*	52	Chairman of the Board, Chief Executive Officer and Director
Harry N. Pefanis*	53	Vice Chairman and Director
Dean Liollo*	52	President and Director
Al Swanson*	46	Senior Vice President, Chief Financial Officer and Director
Benjamin J. Reese	54	Senior Vice President Commercial
Todd Brown	45	Vice President Optimization
Richard K. McGee*	49	Vice President Legal and Business Development and Secretary
Dan Noack	40	Vice President Operations
Donald C. O Shea*	40	Controller and Chief Accounting Officer
Victor Burk	61	Director and Member of Audit** Committee
Bobby S. Shackouls	60	Director and Member of Audit Committee
Arthur L. Smith	58	Director and Member of Audit Committee

* Indicates an executive officer for purposes of Item 401(b) of Regulation S-K.

** Indicates chairman of committee.

Greg L. Armstrong has served as Chairman of the Board, Chief Executive Officer and Director of our general partner since January 2010 and as Chairman of the Board, Chief Executive Officer and Director of PAA's general partner since PAA's formation in 1998. In addition, he was President, Chief Executive Officer and director of Plains Resources Inc. from 1992 to May 2001. He previously served Plains Resources as President and Chief Operating Officer from October to December 1992; Executive Vice President and Chief Financial Officer from June to October 1992; Senior Vice President and Chief Financial Officer from 1991 to 1992; Vice President and Chief Financial Officer from 1984 to 1991; Corporate Secretary from 1981 to 1988; and Treasurer from 1984 to 1987. Mr. Armstrong is also a director of the Federal Reserve Bank of Dallas, Houston Branch, and National Oilwell Varco, Inc. Mr. Armstrong previously served as a director of BreitBurn Energy Partners, L.P. We believe that Mr. Armstrong's experience as chairman of the board and chief executive officer of PAA and his extensive knowledge of the energy industry brings substantial experience and leadership skills to the board.

Harry N. Pefanis has served as Vice Chairman and Director of our general partner since January 2010 and as President and Chief Operating Officer of PAA's general partner since PAA's formation in 1998. In addition, he was Executive Vice President - Midstream of Plains Resources from May 1998 to May 2001. He previously served Plains Resources as Senior Vice President from February 1996 until May 1998; Vice President - Products Marketing from 1988 to February 1996; Manager of Products Marketing from 1987 to 1988; and Special Assistant for Corporate Planning from 1983 to 1987. Mr. Pefanis was also President of several former midstream subsidiaries of Plains Resources until PAA's formation. Mr. Pefanis is also a director of Settoon Towing, LLC. We

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believe that Mr. Pefanis' extensive energy industry background, particularly the five years he has spent serving as part of the management team of PAA's natural gas storage business, brings important experience and skill to the board.

Dean Liollo has served as President and Director of our general partner since January 2010. He has served as President of PAA's natural gas storage business since November 2008. Prior to joining PAA's natural gas storage business, Mr. Liollo served as President, Chief Executive Officer and Director of Energy South, Inc. from August 2006 until its acquisition by Sempra in October 2008. He previously spent 23 years at Centerpoint Energy, most recently serving as Division President and COO of Southern Gas Operations. We believe that Mr. Liollo's more than 25 years of experience in the energy industry, most notably his experience managing natural gas storage operations, including as a director and chief executive officer of a public natural gas storage company, provides a critical resource and skill set to the board.

Al Swanson has served as Senior Vice President, Chief Financial Officer and Director of our general partner since January 2010 and as Executive Vice President and Chief Financial Officer of PAA since February 2011. He previously served as Senior Vice President and Chief Financial Officer of PAA's general partner from November 2008 until February 2011, as Senior Vice President - Finance of PAA's general partner from August 2008 until November 2008 and as Senior Vice President - Finance and Treasurer from August 2007 until August 2008. He served as Vice President - Finance and Treasurer of PAA's general partner from August 2005 to August 2007, as Vice President and Treasurer from February 2004 to August 2005 and as Treasurer from May 2001 to February 2004. In addition, he held finance related positions at Plains Resources including Treasurer from February 2001 to May 2001 and Director of Treasury from November 2000 to February 2001. Prior to joining Plains Resources, he served as Treasurer of Santa Fe Snyder Corporation from 1999 to October 2000 and in various capacities at Snyder Oil Corporation including Director of Corporate Finance from 1998, Controller - SOCO Offshore, Inc. from 1997, and Accounting Manager from 1992. Mr. Swanson began his career with Apache Corporation in 1986 serving in internal audit and accounting. Mr. Swanson has nearly 25 years of experience in the energy industry, serving a number of public companies in the areas of finance, treasury, accounting and internal audit. We believe that this extensive background, coupled with his expertise as chief financial officer of PAA, lends significant financial and accounting experience and skill to the board.

Benjamin J. Reese has served as Senior Vice President - Commercial of our general partner since June 2010. Mr. Reese has 30 years of experience in the natural gas industry. Prior to joining PNG, he was President of Sempra Midstream since October 2008. From 2007 to October 2008, Mr. Reese served as President and Chief Operating Officer of EnergySouth Midstream, Inc. - the natural gas storage, pipeline transportation and midstream services subsidiary of EnergySouth, Inc., which was acquired by Sempra in October 2008. From 1998 to 2007, he served as Senior Vice President and Chief Commercial Officer for CenterPoint Energy. Prior to joining CenterPoint Energy, Mr. Reese spent 18 years in positions of increasing responsibility with USX-Delhi Pipelines and successor companies. Mr. Reese is a former board member of the National Energy Services Association and a current board member of the Southern Gas Association. Mr. Reese holds a Bachelor of Science degree in Chemical Engineering from Texas A&M University.

Todd Brown has served as Vice President - Optimization of our general partner since June 2010. Mr. Brown has over 20 years of experience in the natural gas industry. Prior to joining PNG, he was Vice President - Commercial of Sempra Pipelines & Storage since October 2008. From 2007 to October 2008, Mr. Brown served as Vice President - Commercial of EnergySouth Midstream, Inc. From 2003 to 2007, he served as Vice President - Natural Gas Trading for CenterPoint Energy. From 1988 to 2003, Mr. Brown served in various capacities in the natural gas businesses of several companies, including Mirant, Coral Energy, USX-Delhi Pipelines, Lone Star Gas and Santa Fe Minerals. Mr. Brown holds a Bachelor of Business Administration degree from Stephen F. Austin State University.

Richard K. McGee has served as Vice President - Legal and Business Development and Secretary of our general partner since January 2010. He has served as Vice President of PAA's natural gas storage business since September 2009. From January 1999 to July 2009, he was employed by Duke Energy, serving as President of Duke Energy International from October 2001 through July 2009 and serving as general counsel of Duke Energy Services from January 1999 through September 2001. He previously spent 12 years at Vinson & Elkins L.L.P., where he was a partner with a focus on acquisitions, divestitures and development work for various clients in the energy industry.

Dan Noack has served as Vice President Operations of our general partner since January 2010. He has served as Vice President of Operations of PAA's natural gas storage business since July 2008. Most recently, from January 2005 until June 2008, he served as storage manager for Energy Transfer Partners responsible for their three storage assets and 76 Bcf of working gas capacity, and from January 2002 until December 2004, he served as a storage consultant for El Paso Field Services (GulfTerra) responsible for their eight storage assets, 26 cavern wells, 23 Bcf of working gas capacity and 40 MMbbls of liquid storage capacity.

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Donald C. O Shea has served as Controller of our general partner since February 2010 and as Chief Accounting Officer since August 2010. Previously he served as Director, Special Projects of PAA's general partner from November 2009 to January 2010. Prior to joining us, Mr. O Shea spent 15 years working for the accounting firm PricewaterhouseCoopers LLP.

Victor Burk has served as a Director of our general partner since April 2010. Since April 2009, Mr. Burk has been a Managing Director for Alvarez and Marsal, a privately owned professional services firm. From 2005 to 2009, Mr. Burk was the global energy practice leader for Spencer Stuart, a privately owned executive recruiting firm. Prior to joining Spencer Stuart, Mr. Burk served as managing partner of Deloitte & Touche's global oil and natural gas group from 2002 to 2005. He began his professional career in 1972 with Arthur Andersen and served as managing partner of Arthur Andersen's global oil and natural gas group from 1989 until 2002. Mr. Burk is on the board of directors of EV Management, LLC, the general partner of the general partner of EV Energy Partners, L.P., a publicly traded limited partnership engaged in the acquisition, development and production of oil and natural gas. Mr. Burk also serves as a board member of the Independent Petroleum Association of America (Southeast Texas Region) and the Sam Houston Area Council of the Boy Scouts of America. He received a BBA in Accounting from Stephen F. Austin State University, graduating with highest honors. The board of directors has determined that Mr. Burk is independent under applicable NYSE rules and qualifies as an Audit Committee Financial Expert. We believe that Mr. Burk's background, spanning over 30 years of extensive public accounting and consulting in the energy industry, coupled with his demonstrated leadership abilities, brings valuable expertise and insight to the board.

Bobby S. Shackouls has served as a Director of our general partner since April 2010. Mr. Shackouls served as Chairman of Burlington Resources Inc. from 1997 until its acquisition by ConocoPhillips in 2006. He also served as President and Chief Executive Officer of Burlington Resources from 1995 until 2006. Mr. Shackouls currently serves as a director of ConocoPhillips and The Kroger Co. The board of directors has determined that Mr. Shackouls is independent under applicable NYSE rules. We believe that Mr. Shackouls' extensive experience within the energy industry offers valuable perspective and, in tandem with his long history of leadership as the CEO of a public company, make him highly qualified to serve as a member of the board.

Arthur L. Smith has served as a Director of our general partner since December 2010. Mr. Smith is President and Managing Member of Triple Double Advisors, LLC, an investment advisory firm focused on the energy industry. Mr. Smith was Chairman and CEO of John S. Herold, Inc. (a petroleum research and consulting firm) from 1984 to 2007. From 1976 to 1984, Mr. Smith was a securities analyst with Argus Research Corp., The First Boston Corporation and Oppenheimer & Co., Inc. Mr. Smith holds the Chartered Financial Analyst, or CFA, designation. He serves on the board of non-profit Dress for Success Houston. He is a director of Pioneer Natural Resources GP LLC, the general partner of Pioneer Southwest Energy Partners, L.P., and he served as a director of Plains All American GP LLC, the general partner of PAA, from February 1999 until December 2010. Mr. Smith received a BA from Duke University and an MBA from NYU's Stern School of Business. The board of directors has determined that Mr. Smith is independent under applicable NYSE rules and qualifies as an Audit Committee Financial Expert. In addition to his qualifications as an Audit Committee Financial Expert, Mr. Smith has more than 30 years of extensive and intensive experience in the energy sector as an oil analyst, prior board member (Parker & Parsley Petroleum Company, Cabot Oil & Gas Corporation, Evergreen Resources, Inc. and the New York Society of Security Analysts) and industry observer. We believe that his acute knowledge of the industry and his executive background provide a critical resource and skill set to the Board.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Securities Exchange Act of 1934 requires directors, executive officers and persons who beneficially own more than ten percent of a registered class of our equity securities to file with the SEC and the NYSE initial reports of ownership and reports of changes in ownership of such equity securities. Such persons are also required to furnish us with copies of all Section 16(a) forms that they file. Such reports are accessible on or through our Internet website at <http://www.pnglp.com>.

Based solely upon a review of the copies of Forms 3 and 4 furnished to us, or written representations from certain reporting persons that no Forms 5 were required, we believe that our executive officers and directors complied with all filing requirements with respect to transactions in our equity securities during 2010.

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**Item 11. *Executive Compensation*
Compensation Committee Report**

Our general partner's board of directors performs the functions of a compensation committee. The board of directors has reviewed and discussed with management the compensation discussion and analysis contained in this Annual Report on Form 10-K. Based on those reviews and discussions, the board of directors has recommended that the compensation discussion and analysis be included in the Annual Report on Form 10-K for the year ended December 31, 2010 for filing with the SEC.

Greg L. Armstrong
Harry N. Pefanis
Dean Liollo
Al Swanson
Victor Burk
Bobby S. Shackouls
Arthur L. Smith

Compensation Committee Interlocks and Insider Participation

Our general partner's board of directors performs the functions of a compensation committee. Mr. Armstrong is a director, and Messrs. Armstrong, Pefanis and Swanson are executive officers, of the general partner of PAA. Messrs. Armstrong, Pefanis, Liollo and Swanson are officers of the company. All directors, including Messrs. Armstrong, Pefanis, Liollo and Swanson, participated in deliberations of the board concerning executive compensation during the last fiscal year; however, Mr. Liollo was not a participant in certain portions of the meetings during the discussion of his compensation.

Compensation Discussion and Analysis

Background

All of our executive officers and other personnel necessary for our business to function are employed and compensated by PAA's general partner, subject to reimbursement by us. We and our general partner were formed in January 2010, therefore, we incurred no cost or liability with respect to compensation of our executive officers, nor has our general partner accrued any liabilities for management incentive or retirement benefits for our executive officers, for fiscal years prior to 2010. Our initial public offering was completed on May 5, 2010.

The board of directors of our general partner retains and exercises responsibility and authority for compensation-related decisions for executive officers who devote substantially all of their time to managing our business. The compensation committee of PAA's general partner retains and exercises responsibility and authority for compensation-related decisions for executive officers with shared responsibilities to both us and PAA, but who devote the majority of their time to PAA's other business activities. Our officers manage our business as part of the service provided by PAA under the omnibus agreement, and to the extent allocated to us and not otherwise excluded from reimbursement, the compensation for all of our executive officers is indirectly paid by us through reimbursements to PAA. Our general partner's board of directors is also responsible for the administration of our LTIP and other equity incentive programs and for compensation of our general partner's non-employee directors.

We are majority owned and controlled by PAA and our assets, liabilities and results of operations are consolidated in PAA's financial statements. During 2010, our contribution to adjusted EBITDA represented less than 5% of PAA's consolidated adjusted EBITDA. Messrs. Armstrong, Pefanis and Swanson are executive officers of the general partner of PAA and devote the majority of their time to PAA's other business activities. Except as noted below under Elements of Compensation Transaction/Transition Grants, the activities of Messrs. Armstrong, Pefanis and Swanson with respect to PNG were a minor consideration for the compensation committee and board of directors of PAA in the determination of cash compensation paid to or equity incentives awarded to such individuals. Information relating to their compensation is set forth in PAA's Annual Report on Form 10-K. Accordingly, the following discussion relates primarily to the officers who devote substantially all of their time to our business activities and for whom the responsibility and authority for compensation related decisions reside directly with the board of directors of our general partner (the Dedicated Named Executive Officers).

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Similar to PAA, we employ a compensation philosophy that emphasizes pay-for-performance (primarily the ability to increase sustainable quarterly distributions to unitholders), both on an individual and entity level, and places the majority of each officer's compensation at risk. We believe our pay-for-performance approach aligns the interests of our executive officers with that of our unitholders, and at the same time enables us to maintain a lower level of base overhead in the event our operating and financial performance fails to meet expectations. Our executive compensation is designed to attract and retain individuals with the background and skills necessary to successfully execute our business model in a demanding environment, to motivate those individuals to reach near-term and long-term goals in a way that aligns their interest with that of our unitholders, and to reward success in reaching such goals. We use three primary elements of compensation to fulfill that design—salary, cash bonuses and long-term equity incentive awards. Cash bonuses and equity incentives (as opposed to salary) represent the performance driven elements. They are also flexible in application and can be tailored to meet our objectives. The determination of specific individuals' cash bonuses reflects their relative contribution to achieving or exceeding annual goals, and the determination of specific individuals' long-term incentive awards is based on their expected contribution in respect of longer term performance objectives. We do not maintain a defined benefit or pension plan for our executive officers, because we believe such plans primarily reward longevity rather than performance. PAA provides a basic benefits package generally to all employees, which includes a 401(k) plan and health, disability and life insurance. Employees provided to us under the omnibus agreement will enjoy the same basic benefits. In instances considered necessary for the execution of their job responsibilities, we will reimburse certain of our executive officers and other employees for club dues and similar expenses.

Elements of Compensation

Salary. We do not benchmark our salary or bonus amounts. In practice, we believe our salaries are generally competitive with the narrower universe of large-cap master limited partnerships, but are moderate relative to the broad spectrum of energy industry competitors for similar talent.

Cash Bonuses. Our cash bonuses consist of annual discretionary bonuses in which all of our Dedicated Named Executive Officers potentially participate and a quarterly bonus program in which Mr. Liollo was eligible to participate in 2010.

Long-Term Incentive Awards. The primary long-term measure of our performance is our ability to increase our sustainable quarterly distribution to our unitholders. We use performance-indexed phantom unit grants to encourage and reward timely achievement of targeted distribution levels and align the long-term interests of our Dedicated Named Executive Officers with those of our unitholders. These grants also require minimum service periods as further described below in order to encourage long-term retention. A phantom unit is the right to receive, upon the satisfaction of vesting criteria specified in the grant, a common unit (or cash equivalent). We do not use options as a form of incentive compensation. Unlike vesting of an option, vesting of a phantom unit results in delivery of a common unit or cash of equivalent value as opposed to a right to exercise. Phantom units vest upon the later of achievement of targeted distribution threshold levels or other performance conditions and continued employment for periods ranging from two to five years. Distribution performance thresholds are generally consistent with our targeted range for distribution growth, as adjusted from time to time. To encourage accelerated performance, if we meet certain distribution thresholds prior to meeting the minimum service requirement for vesting of certain awards, our Dedicated Named Executive Officers have the right to receive distributions on phantom units prior to vesting in the underlying common units (referred to as distribution equivalent rights, or "DERs").

In 2010, our general partner authorized the creation of Class B units of PNGS GP LLC and authorized the board of directors to issue grants of Class B units to create additional long-term incentives for our management. The entire economic burden of the Class B units is borne solely by our general partner and does not impact our cash or units outstanding.

The Class B units are subject to restrictions on transfer and generally become incrementally earned (entitled to participate in distributions) upon achievement of certain performance thresholds. As of February 14, 2011, none of the Class B units granted in 2010 had been earned.

To encourage retention following achievement of these performance benchmarks, Class B units remain forfeitable (whether or not earned) if the holder terminates his employment prior to May 5, 2015. Additionally, the annual participation amount is capped to the maximum amount paid at the time of termination of employment, such that the holder does not benefit from growth in cash distributions experienced after the holder's employment terminates. See Item 13. Certain Relationships and Related

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Transactions, and Director Independence Our General Partner Class B Units of Our General Partner.

Transaction/Transition Grants. In connection with the initial public offering of PNG, PAA created a plan based on PNG equity, which is designed to reward and create incentive for certain of PAA's officers who were instrumental in developing the natural gas storage business and bringing it to the point of the IPO, and who will continue to allocate meaningful amounts of time to the business. Recipients of these transaction/transition grants included Messrs. Armstrong, Pefanis and Swanson. Such grants are transactional and transitional and are not expected to be a recurring component of these individuals' compensation arrangements. Vesting terms are intended to align the interests of these individuals with those of PAA as such interests pertain to achieving specific future performance benchmarks that are significant to PNG and to PAA's equity holdings in PNG. The transaction/transition grants were awarded by the compensation committee of the board of directors of PAA, not by our board of directors. See Summary Compensation Table.

Relation of Compensation Elements to Compensation Objectives

Our compensation program is designed to motivate, reward and retain our executive officers. Cash bonuses serve as a near-term motivation and reward for achieving the annual goals established at the beginning of each year. Phantom unit awards (and associated DERs) and Class B units provide motivation and reward over both the near-term and long-term for achieving performance thresholds necessary for earning and vesting. Transaction/transition grants, as the title implies, focus on contributions to the success of a specific transaction, including reward for inception and consummation, as well as incentive for effective transition and execution of the business plan going forward. The level of annual bonus and phantom unit awards reflect the moderate salary profile and the significant weighting towards performance based, at-risk compensation. Salaries and cash bonuses (particularly quarterly bonuses), as well as currently payable DERs associated with unvested phantom units and earned Class B units subject to forfeiture upon termination by the holder, serve as near-term retention tools. Longer-term retention is facilitated by the minimum service periods of up to five years associated with phantom unit awards, the long-term vesting profile of the Class B units and, in the case of certain executives, annual bonuses that are payable over a three-year period. To facilitate our general partner's board of directors in reviewing and making recommendations, a compensation tally sheet is prepared by our CEO and internal counsel and provided to the board.

We stress performance-based compensation elements to attempt to create a performance-driven environment in which our executive officers are (i) motivated to perform over both the short term and the long term, (ii) appropriately rewarded for their services and (iii) encouraged to remain with us even after meeting long-term performance thresholds in order to meet the minimum service periods and by the potential for rewards yet to come. We believe our compensation philosophy as implemented by application of the three primary compensation elements (i) aligns the interests of our Dedicated Named Executive Officers with our unitholders, (ii) positions us to achieve our business goals, and (iii) effectively encourages the exercise of sound judgment and risk-taking that is conducive to creating and sustaining long-term value. We believe the processes employed by the board in applying the elements of compensation (as discussed in more detail below) provide an adequate level of oversight with respect to the degree of risk being taken by management to achieve short-term performance goals. See *Relation of Compensation Policies and Practices to Risk Management*.

Application of Compensation Elements

Salary. We do not make systematic annual adjustments to the salaries of our Dedicated Named Executive Officers. Instead, when indicated as a result of adding new senior management members to keep pace with our overall growth, necessary salary adjustments may be made to maintain hierarchical relationships between senior management levels and the new senior management members.

Annual Discretionary Bonuses. Annual discretionary bonuses are determined based on our performance relative to our annual plan forecast and public guidance (typically provided quarterly in conjunction with release of earnings), our distribution growth targets, and other quantitative and qualitative goals established at the beginning of each year. Such annual objectives are discussed and reviewed with the board of directors in conjunction with the review and authorization of the annual plan.

At the end of each year, the CEO performs a quantitative and qualitative assessment of our performance relative to our goals. Key quantitative measures include earnings before interest, taxes, depreciation and amortization,

excluding items affecting comparability (adjusted EBITDA), relative to established guidance, as well as the growth in the annualized quarterly distribution level per common unit relative to annual growth targets. Our primary performance metric is our ability to generate increasing and sustainable cash distributions to our unitholders. Accordingly, although net income and net income per unit are monitored to

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highlight inconsistencies with primary performance metrics, as is our market performance relative to our MLP peers and major indices, these metrics are considered secondary performance measures. The CEO's written analysis of our performance examines our accomplishments, shortfalls and overall performance against opportunity, taking into account controllable and non-controllable factors encountered during the year.

The resulting document and supporting detail is submitted to the board of directors of our general partner for review and comment. Based on the conclusions set forth in the annual performance review, the CEO submits recommendations to the board of directors for bonuses to our Dedicated Named Executive Officers, taking into account the relative contribution of the individual officer. There are no set formulas for determining the annual discretionary bonus for our Dedicated Named Executive Officers. Factors considered by the CEO in determining the level of bonus in general include (i) whether or not we achieved the goals established for the year and any notable shortfalls relative to expectations; (ii) the level of difficulty associated with achieving such objectives based on the opportunities and challenges encountered during the year; (iii) current year operating and financial performance relative to both public guidance and prior year's performance; (iv) significant transactions or accomplishments for the period not included in the goals for the year; (v) our relative prospects at the end of the year with respect to future growth and performance; and (vi) our positioning at the end of the year with respect to our targeted credit profile. The CEO takes these factors into consideration as well as the relative contributions of each of our Dedicated Named Executive Officers to the year's performance in developing his recommendations for bonus amounts.

These recommendations are discussed with and submitted to the board of directors for its review and approval.

Quarterly Bonus Program. Mr. Liollo and certain other members of our management team are directly involved in activities that generate or significantly influence partnership earnings. These individuals, along with other employees in our commercial group, participate in a quarterly bonus pool, the size of which is based on adjusted EBITDA, which directly rewards for quarterly performance the commercial and asset managing employees who participate. This quarterly incentive provides a direct incentive to optimize quarterly performance even when, on an annual basis, other factors might negatively affect bonus potential. Mr. Liollo makes recommendations to Mr. Pefanis with respect to allocation of quarterly bonus amounts among all other participants based on relative contribution, and, after review and modification, if any, Mr. Pefanis submits recommendations to Mr. Armstrong for review, modification and approval, as appropriate. Messrs. Pefanis and Armstrong do not participate in the quarterly bonus program. The quarterly bonus amounts for Mr. Liollo are taken into consideration in determining the recommended annual discretionary bonus submitted by the CEO to the full board.

Long-Term Incentive Awards. Our Dedicated Named Executive Officers received phantom unit awards in connection with our initial public offering. We will not make systematic annual phantom unit awards to our Dedicated Named Executive Officers. Instead, our objective is to time the granting of awards such that as performance thresholds are met for existing awards, additional long-term incentives are created. Thus, performance is rewarded by relatively greater frequency of awards and lack of performance by relatively lesser frequency of awards. Generally, we believe that a performance-based grant cycle and extended time-vesting requirements will provide a balance between a meaningful retention period for us and a visible, reachable reward for the executive officer. Achievement of performance targets does not shorten the minimum service period requirement. If top performance targets on outstanding awards are achieved in the early part of this cycle, new awards will be granted with higher performance thresholds, and the minimum service periods of the new awards will be generally synchronized with the remaining time-vesting requirements of outstanding awards in a manner designed to encourage extended retention of our Dedicated Named Executive Officers. Accordingly, any new arrangements inherently take into account the value of awards where performance levels have been achieved but have not yet vested due to ongoing service period requirements, but will not take into consideration previous awards that have fully vested.

As an additional means of providing longer-term, performance-based officer incentives that require extended periods of employment to realize the full benefit, our general partner authorized the creation of Class B units of PNGS GP LLC, which the board of directors is authorized to administer. See Elements of Compensation Long-Term Incentives. These Class B units are limited to 165,000 authorized units, of which approximately 90,750 were outstanding as of December 31, 2010 pursuant to individual restricted units agreements between PNGS GP LLC and certain members of management. As of December 31, 2010, our Dedicated Named Executive Officers held 50,875 of

the restricted Class B units. The remaining available Class B units are administered at the discretion of the board of directors and may be awarded upon advancement, exceptional performance or other change in circumstance of an existing member of management, or upon the addition of a new individual to the management team.

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Application in 2010

A major objective for 2010 was to optimize the structure and performance of PAA's natural gas storage platform, which resided in a predecessor entity to PNG and was a wholly owned subsidiary of PAA. In that regard, at the beginning of 2010, PAA and PNG established five goals for the natural gas storage business:

1. Achieve or exceed plan;
2. Evaluate and implement the optimal structure for PAA's natural gas storage business;
3. Crystallize and implement a strategy for merchant activities in the natural gas storage business;
4. Deliver expansion projects on time and on budget; and
5. Selectively pursue strategic and accretive acquisitions.

In general and as discussed below, we substantially met or exceeded four of the five goals:

Based on PAA's long-term growth plans for the natural gas storage platform and the cost of capital benefits, we concluded that the optimal structure was to place all of PAA's natural gas storage assets into a separate MLP controlled and majority owned by PAA. PNG's initial public offering (IPO) was completed in May 2010.

During 2010, we expanded our commercial management team and formed a commercial optimization group and significant actions were taken to establish appropriate risk-management controls, formulate and document key strategies and fill out the remaining infrastructure requirements.

We executed our 2010 capital program on schedule and under cost forecasts, with creation of working gas capacity in line with 2010 guidance.

We performed detailed acquisition analyses and submitted proposals on several potential transactions. In late December, we executed a definitive agreement to acquire 100% of the equity interests in SG Resources Mississippi, L.L.C., which entity owns the Southern Pines Energy Center natural gas storage facility, for approximately \$750 million. This acquisition closed in February 2011.

We fell short of our goal to meet or exceed 2010 Plan forecast primarily due to challenging market conditions and delayed recognition of the deterioration of such market conditions. Following the IPO, our forecast was adjusted for incremental public company costs and changing market conditions. Actual results were within 3% of such adjusted forecast and we met or exceeded our public guidance for the third and fourth quarters of 2010.

Additionally, during the eight months following our IPO, we paid distributions of \$0.55 per common unit. As a result of these distributions and appreciation in our unit price above the IPO level, our unit holders realized a total return of approximately 18.5% (29% annualized).

For 2010, the elements of compensation were applied as described below. No material additions or changes to these elements are contemplated for 2011.

Salary. No salary adjustments for Dedicated Named Executive Officers were recommended or made in 2010. See Narrative Disclosure to Summary Compensation Table and Grants of Plan-Based Awards Table.

Cash Bonuses. Based on the CEO's annual performance review and the individual performance of each of our Dedicated Named Executive Officers, the CEO recommended to the board of directors and the board of directors approved the annual bonuses reflected in the Summary Compensation Table and notes thereto. Such amounts take into account the performance relative to our 2010 goals; the absence or existence of shortfalls relative to expectations; the level of difficulty associated with achieving such objectives; our relative positioning at the end of the year with respect to future growth and performance; the significant transactions or accomplishments for the period not included

in the goals for the year; and our positioning at the end of the year with respect to our targeted credit profile. At the end of 2010, the annual bonus cycle for the Dedicated Named Executive Officers was shifted from a compensation cycle coincident with the natural gas storage season (April 1 through March 31) to a calendar year cycle. As a result, for the first year, annual bonus amounts were reduced to reflect the prorated period from April 1, 2010 to December 31, 2010.

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Long-Term Incentive Awards. In May 2010, the board of directors granted two tranches of phantom unit awards to our Dedicated Named Executive Officers and other members of our senior management team that devote substantially all of their time to us. These grants are intended to encourage continued growth and fundamental performance that will support future distribution growth. The first tranche of phantom units will vest in one-third increments on the date on which we pay an annualized quarterly distribution of at least \$1.55, \$1.80 and \$1.90 per common unit and the later of the May 2012, May 2013 and May 2014 distribution dates, respectively. Such awards have associated DERs that become payable in 25% increments upon achieving quarterly distribution levels of \$1.48, \$1.56, \$1.76 and \$1.90, without regard to the minimum service period. Any of these first tranche phantom units that remain outstanding as of the May 2015 distribution date for which the performance thresholds have not been met will be forfeited.

The second tranche of phantom unit awards will vest as follows: 20% will vest as of the date on which our Series A Subordinated Units convert into Common Units; 20% will vest as of the date on which the first tranche of our Series B Subordinated Units convert into Series A Subordinated Units or Common Units; 20% will vest as of the date on which the second tranche of our Series B Subordinated Units convert into Series A Subordinated Units or Common Units; 20% will vest as of the date on which the third tranche of our Series B Subordinated Units convert into Series A Subordinated Units or Common Units; and 20% will vest as of the date on which the fourth tranche of our Series B Subordinated Units convert into Series A Subordinated Units or Common Units. Conversion of the Series A Subordinated Units and Series B Subordinated Units is subject to certain performance conditions set forth in our partnership agreement. Any of these second tranche phantom units that remain outstanding as of January 1, 2018 shall expire without vesting on such date.

Upon vesting, the phantom units are payable on a one-for-one basis in common units.

See Narrative Disclosure to Summary Compensation Table and Grants of Plan-Based Awards Table and Application of Compensation Elements.

The 2010 awards included grants to our Dedicated Named Executive Officers as follows: Mr. Liollo, 105,000 of the first tranche and 105,000 of the second tranche; and Mr. McGee, 55,000 of the first tranche and 55,000 of the second tranche. Messrs. Armstrong, Pefanis and Swanson were not awarded any similar grants by us because they have been separately compensated by way of the transaction/transition grants described below.

Transaction/Transition Grants. In September 2010, PAA entered into transaction/transition grant agreements with Messrs. Armstrong, Pefanis and Swanson, pursuant to which these individuals acquired phantom common units, phantom series A subordinated units and phantom series B subordinated units representing a portion of the limited partner interests of PNG issued to PAA in connection with PNG's IPO. Distribution equivalent rights, payable by PAA in cash, were also granted with respect to the phantom common units and phantom series A subordinated units.

The phantom units will vest and be payable as follows: (i) the phantom common units will vest 50% on May 5, 2011 and 50% on May 5, 2012, and be payable one-for-one by PAA in Common Units of PNG; (ii) the phantom series A subordinated units will vest in connection with the conversion of the Series A Subordinated Units into Common Units, and be payable one-for-one by PAA in Common Units of PNG; and (iii) the phantom series B subordinated units will vest in increments of 20%, 21%, 15%, 22% and 22%, respectively, in connection with the conversion of the First through Fifth Tranches of Series B Subordinated Units. Upon vesting, the phantom series B subordinated units will be payable one-for-one by PAA in Series A Subordinated Units or Common Units of PNG it receives upon conversion of the Series B Subordinated Units. The vesting terms align the interests of the recipient with the interests of PNG unitholders (including PAA). Any phantom series A subordinated units and any phantom series B subordinated units that have not vested as of December 31, 2018 will be automatically cancelled on such date. The number of phantom units of each class or series granted by PAA to Messrs. Armstrong, Pefanis and Swanson is as follows: Mr. Armstrong, 62,000 each of phantom common units, phantom series A subordinated units and phantom series B subordinated units; Mr. Pefanis, 42,000 each of phantom common units, phantom series A subordinated units and phantom series B subordinated units; and Mr. Swanson, 21,000 each of phantom common units, phantom series A subordinated units and phantom series B subordinated units.

Other Compensation Related Matters

Equity Ownership in PNG. As of December 31, 2010, our Named Executive Officers beneficially owned, in the aggregate, approximately 249,200 of our common units (excluding any unvested equity awards), and 50,875 Class B units of our general

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partner. Although we encourage our Named Executive Officers to acquire and retain ownership in the Partnership, we do not have a policy requiring maintenance of a specified equity ownership level. In connection with the transaction/transition grants, Messrs. Armstrong, Pefanis and Swanson indicated their intent to hold the common units they purchased in the IPO for a period of at least two years. Our policies prohibit our Named Executive Officers from using puts, calls or options to hedge the economic risk of their ownership.

Recovery of Prior Awards. Except as provided by applicable laws and regulations, we do not have a policy with respect to adjustment or recovery of awards or payments if relevant company performance measures upon which previous awards were based are restated or otherwise adjusted in a manner that would reduce the size of such award or payment.

Section 162(m). With respect to the deduction limitations under Section 162(m) of the Code, we are a limited partnership and do not meet the definition of a corporation under Section 162(m).

Change in Control Triggers. The employment agreement for Mr. Liollo, the long-term incentive plan grants to our Dedicated Named Executive Officers and the Class B restricted units agreements include severance payment provisions or accelerated vesting triggered upon a change of control, as defined in the respective agreement. In the case of the long-term incentive plan grants, the provision becomes operative only if the change in control is accompanied by a change in status (such as the termination of employment by our general partner or PAA's general partner, as applicable). This double trigger arrangement provides assurance to the executive, but does not offer a windfall to the executive when there has been no real change in employment status. The provision in the employment agreement for Mr. Liollo becomes operative only if the executive's employment is terminated by our general partner within six months of the change in control. The Class B restricted units agreements generally call for vesting (upon a change in control) of any units that have already been earned, plus the next increment of units that could be earned at the next distribution threshold. Any remaining Class B restricted units would be forfeited (unless waived at the discretion of the general partner or acquirer as the case may be). See Employment Agreements and Potential Payments upon Termination or Change-in-Control. Messrs. Armstrong, Pefanis and Swanson have transaction/transition grants and other long-term incentives, and Messrs. Armstrong and Pefanis have employment agreements, that include provisions for a change in control of PAA, which are described in PAA's Annual Report on Form 10-K. The provision of severance or equity acceleration for certain terminations and change of control help to create a retention tool by assuring the executive that the benefit of the employment arrangement will be at least partially realized despite the occurrence of an event that would materially alter the employment arrangement.

Relation of Compensation Policies and Practices to Risk Management

Our compensation policies and practices reflect a similar philosophy and approach as PAA's. Accordingly, such policies and practices are designed to provide rewards for short-term and long-term performance, both on an individual basis and at the entity level. In general, optimal financial and operational performance, particularly in a competitive business, requires some degree of risk-taking. Accordingly, the use of compensation as an incentive for performance can foster the potential for management and others to take unnecessary or excessive risks to reach performance thresholds which qualify them for additional compensation. For us, such risks would primarily attach to the commercial marketing activities that we are developing, as well as to the execution of capital expansion projects and acquisitions and the realization of associated returns.

From a risk management perspective, our policy is to conduct our commercial activities within pre-defined risk parameters that are closely monitored and are structured in a manner intended to control and minimize the potential for unwarranted risk-taking. See Item 7a. Quantitative and Qualitative Disclosures About Market Risk. We also routinely monitor and measure the execution and performance of our capital projects and acquisitions relative to expectations.

Our compensation arrangements contain a number of design elements that serve to minimize the incentive for taking unwarranted risk to achieve short-term, unsustainable results. Those elements include delaying the rewards and subjecting such rewards to forfeiture for terminations related to violations of our risk management policies and practices or of our code of conduct.

In combination with our risk-management practices, we do not believe that risks arising from our compensation policies and practices for our employees are reasonably likely to have a material adverse effect on us.

Table of Contents**Summary Compensation Table**

The following table sets forth certain compensation information for our Chief Executive Officer, Chief Financial Officer, and the three other most highly compensated executive officers in 2010 (our Named Executive Officers). We reimburse PAA for expenses incurred on our behalf, including the costs of compensation paid to Messrs. Liollo and McGee (excluding the costs of the obligations represented by the Class B units). PAA pushes down to us the compensation expense associated with the transaction/transition grants.

Because we were not capitalized before our May 2010 IPO, our compensation of personnel (including Named Executive Officers), did not commence until that time. Additionally, at the end of 2010, the annual bonus cycle for the Dedicated Named Executive Officers was shifted to a calendar year compensation cycle from a cycle coincident with the natural gas storage season (April 1 through March 31). For ease of presentation and future comparison, the amounts in the table below include full calendar year amounts for salary, quarterly bonuses and all other compensation, but include annual bonuses for only the prorated period from April 1, 2010 to December 31, 2010. Information with respect to annual bonus compensation for our Dedicated Named Executive Officers for the 2009/2010 storage season that ended on March 31, 2010 is included in the footnotes to the table below.

Name and Principal Position	Year	Salary (\$)	Bonus (\$)	Stock Awards (\$) ⁽¹⁾	All Other	Total (\$)
					Compensation (\$) ⁽²⁾	
Greg L. Armstrong (3) Chairman and CEO	2010			3,182,469		3,182,469(1)
Harry N. Pefanis (3) Vice Chairman	2010			2,155,866		2,155,866(1)
Al Swanson (3) Senior Vice President and Chief Financial Officer	2010			1,077,933		1,077,933(1)
Dean Liollo President	2010	250,000	580,000(4)(6)	409,095	15,900	1,254,995
Richard K. McGee Vice President Legal and Business Development	2010	200,000	350,000(5)(6)	214,288	15,660	779,948

- (1) Grant date fair values are presented for (i) transaction/transition grants awarded to Messrs. Armstrong, Pefanis and Swanson, and (ii) LTIP phantom unit grants and Class B restricted units granted to Messrs. Liollo and McGee. Dollar amounts represent the aggregate grant date fair value of transaction/transition grants, phantom units and Class B units granted during the year based on the probable outcome of underlying performance conditions pursuant to FASB ASC Topic 718. For transaction/transition grants awarded in 2010, vesting of 100% of the phantom common units and phantom series A subordinated units, and vesting of 20% of the phantom series B subordinated units, was deemed probable of occurrence on the grant date. For phantom units granted in 2010, none of the performance thresholds for vesting of the first tranche phantom units was deemed probable of occurrence as of the grant date, and 20% of the performance thresholds for vesting of the second tranche phantom units was deemed probable of occurrence as of the grant date. None of the performance thresholds for vesting of the Class B units was deemed probable of occurrence as of the grant date. The maximum grant date fair values of stock awards assuming that the highest level of performance conditions will be met are as follows:

Name	Year	Maximum Grant Date Fair Value (\$)
Greg L. Armstrong	2010	4,172,027
Harry N. Pefanis	2010	2,826,212
Al Swanson	2010	1,413,106
Dean Liollo	2010	4,389,057
Richard McGee	2010	2,283,570

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- (2) Plains All American GP LLC matches 100% of employees' contributions to its 401(k) plan in cash, subject to certain limitations in the plan. All Other Compensation for each of Messrs. Liollio and McGee includes \$14,700 in such contributions for 2010. The remaining amount for each represents premium payments on behalf of such Named Executive Officer for group term life insurance.
- (3) Messrs. Armstrong, Pefanis and Swanson are also executive officers of and are compensated by PAA, with a portion of the costs associated with such overhead being allocated to us under the omnibus agreement. Total compensation for each of Messrs. Armstrong, Pefanis and Swanson, as reported in PAA's Annual Report on Form 10-K for the year ended December 31, 2010, was \$9,509,336, \$7,362,411 and \$3,339,155, respectively. These amounts include duplicative values for transaction/transition grants. PAA's 2010 Annual Report on Form 10-K is available on its website at www.paalp.com.
- (4) Includes quarterly bonuses aggregating \$330,000, and an annual bonus of \$250,000. The amount in the table does not reflect (i) a \$325,000 annual bonus awarded in the second quarter of 2010 for the 2009/2010 storage season, and (ii) a special bonus of \$800,000 awarded in January 2010 (generally attributable to 2009) for Mr. Liollio's efforts in connection with our preparation for the IPO.
- (5) For his efforts in connection with our IPO, \$200,000 of Mr. McGee's annual bonus is being paid by PAA. The amount in the table does not reflect a \$175,000 annual bonus awarded in the second quarter of 2010 for the 2009/2010 storage season, which amount was prorated from his date of employment.
- (6) The annual bonuses for Messrs. Liollio and McGee have been prorated to reflect a shift at the end of 2010 from a compensation cycle tied to the natural gas storage season (April 1 through March 31), to a calendar year cycle. As a result, the annual bonus amounts included in the table are for the period from April 1, 2010 to December 31, 2010. Annual bonuses are payable 60% at the time of award and 20% in each of the two succeeding years.

Grants of Plan-Based Awards Table

The following table sets forth summary information regarding all grants of plan-based awards made to our Named Executive Officers during the fiscal year ended December 31, 2010.

Name	Grant Date	All Other Stock Awards:	
		Number Of Shares Of Stock or Units (#)	Grant Date Fair Value Of Stock and Option Awards (\$)(7)
Greg L. Armstrong	9/9/2010	62,000(1)	1,467,540
	9/9/2010	62,000(2)	1,467,540
	9/9/2010	62,000(3)	247,389
Harry N. Pefanis	9/9/2010	42,000(1)	994,140
	9/9/2010	42,000(2)	994,140
	9/9/2010	42,000(3)	167,586
Al Swanson	9/9/2010	21,000(1)	497,070
	9/9/2010	21,000(2)	497,070
	9/9/2010	21,000(3)	83,793

Dean Liollo	5/24/2010	105,000(4)	409,095
	5/24/2010	105,000(5)	
	7/1/2010	34,375(6)	
Richard K. McGee	5/24/2010	55,000(4)	214,288
	5/24/2010	55,000(5)	
	7/1/2010	16,500(6)	

- (1) These phantom common units will vest 50% on May 5, 2011 and 50% on May 5, 2012, and be payable one-for-one by PAA in Common Units of PNG.
- (2) These phantom series A subordinated units will vest in connection with the conversion of the Series A Subordinated Units into Common Units, and be payable one-for-one by PAA in Common Units of PNG. Any of these phantom series A subordinated units that have not vested as of December 31, 2018 will be automatically cancelled on such date.

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- (3) These phantom series B subordinated units will vest in increments of 20%, 21%, 15%, 22% and 22%, respectively, in connection with the conversion of the First through Fifth Tranches of Series B Subordinated Units. Upon vesting, the phantom series B subordinated units will be payable one-for-one by PAA in Series A Subordinated Units or Common Units of PNG it receives upon conversion of the Series B Subordinated Units. Any of these phantom series B subordinated units that have not vested as of December 31, 2018 will be automatically cancelled on such date.
- (4) These first tranche phantom units will vest (become payable 1-for-1 of our common units) as follows: (i) one-third will vest upon the later of the May 2012 distribution date and the date we pay a quarterly distribution of at least \$0.3875 (\$1.55 annualized), (ii) one third will vest upon the later of the May 2013 distribution date and the date we pay a quarterly distribution of at least \$0.45 (\$1.80 annualized), and (iii) one-third will vest upon the later of the May 2014 distribution date and the date we pay a quarterly distribution of at least \$0.475 (\$1.90 annualized). The phantom units include tandem distribution equivalent rights that vest (distributions become payable as if the underlying common unit were owned) in 25% increments on the dates we pay a quarterly distribution of \$0.37 (\$1.48 annualized), \$0.39 (\$1.56 annualized), \$0.44 (\$1.76 annualized), and \$0.475 (\$1.90 annualized), respectively. Any of these phantom units (and all associated DERs) that have not vested as of the May 2015 distribution date will be forfeited.
- (5) These second tranche phantom units will vest (become payable 1-for-1 of our common units) as follows: 20% will vest as of the date on which our Series A Subordinated Units convert into Common Units; 20% will vest as of the date on which the first tranche of our Series B Subordinated Units convert into Series A Subordinated Units or Common Units; 20% will vest as of the date on which the second tranche of our Series B Subordinated Units convert into Series A Subordinated Units or Common Units; 20% will vest as of the date on which the third tranche of our Series B Subordinated Units convert into Series A Subordinated Units or Common Units; and 20% will vest as of the date on which the fourth tranche of our Series B Subordinated Units convert into Series A Subordinated Units or Common Units. Conversion of the Series A Subordinated Units and Series B Subordinated Units is subject to certain performance conditions set forth in our partnership agreement. Any of these phantom units that remain outstanding as of January 1, 2018 shall expire without vesting on such date.
- (6) These Class B units of PNGS GP LLC were authorized by the board of directors of our general partner to create long-term incentives for our management. Each Class B unit represents a profits interest in PNGS GP LLC, which entitles the holder to participate in future profits and losses from operations, current distributions from operations, and an interest in future appreciation or depreciation in PNGS GP LLC's asset values, but does not represent an interest in the capital of PNGS GP LLC on the applicable grant date of the Class B units. Class B units become earned in 25% increments 180 days after we pay annualized quarterly distributions on our common units of \$2.00, \$2.30, \$2.50 and \$2.70. Earned Class B units will be entitled to their proportionate share of all quarterly cash distributions made by our general partner in excess of \$2.5 million per quarter. Fifty percent of earned units will vest immediately upon becoming earned and 50% will vest on the fifth anniversary of the date of grant. Any Class B units that are earned after the fifth anniversary of the date of grant will fully vest upon becoming earned. Assuming all authorized Class B units are issued, the maximum participation would be 6% of the amount in excess of \$2.5 million per quarter. To encourage retention, Class B units remain forfeitable (whether or not earned) if the holder terminates his employment prior to May 5, 2015. Additionally, the participation amount is capped to the maximum amount paid at the time of termination of employment, such that the holder does not benefit from growth in cash distributions experienced after the holder's employment terminates. Upon the occurrence of a change of control (as defined), (i) all earned units will vest, and (ii) to the extent any of the units are unearned at the time, an incremental 25% of the units originally awarded will vest. All earned Class B units will also vest if they remain outstanding as of May 5, 2015.
- (7)

Represents the grant date fair value of transaction/transition grants, phantom units and Class B units based on the probable outcome of underlying performance conditions pursuant to FASB ASC Topic 718. For transaction/transition grants awarded in 2010, vesting of 100% of the phantom common units and phantom series A subordinated units, and vesting of 20% of the phantom series B subordinated units, was deemed probable of occurrence on the grant date. For phantom units granted in 2010, none of the performance thresholds for vesting of the first tranche phantom units was deemed probable of occurrence as of the grant date, and 20% of the performance thresholds for vesting of the second tranche phantom units was deemed probable of occurrence as of the grant date. None of the performance thresholds for Class B units granted in 2010 was deemed probable of occurrence on the date of grant. The maximum grant date fair value of plan-based awards granted in 2010 is set forth below:

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Name	Grant Date	Quantity	Maximum Grant Date Fair Value (\$)
Armstrong	9/9/10	62,000	1,467,540
	9/9/10	62,000	1,467,540
	9/9/10	62,000	1,236,947
Pefanis	9/9/10	42,000	994,140
	9/9/10	42,000	994,140
	9/9/10	42,000	837,932
Swanson	9/9/10	21,000	497,070
	9/9/10	21,000	497,070
	9/9/10	21,000	418,966
Liollo	5/24/10	105,000	1,990,697
	5/24/10	105,000	2,045,474
	7/1/10	34,375	352,886
McGee	5/24/10	55,000	1,042,746
	5/24/10	55,000	1,071,439
	7/1/10	16,500	169,385

Narrative Disclosure to Summary Compensation Table and Grants of Plan-Based Awards Table

A discussion of 2010 salaries and bonuses for our Dedicated Named Executive Officers and how they fit into the overall compensation array is included in Compensation Discussion and Analysis. The following is a discussion of other material factors necessary to an understanding of the information disclosed in the Summary Compensation Table and Grants of Plan-Based Awards Table above.

Salary As discussed in this Item 11, we do not make systematic annual adjustments to the salaries of our Dedicated Named Executive Officers. In that regard, no salary adjustments were made for any of our Dedicated Named Executive Officers in 2010.

Grants of Plan-Based Awards In May 2010, our Dedicated Named Executive Officers were awarded the following phantom units: Mr. Liollo, 105,000 each of the first tranche and second tranche phantom units and Mr. McGee, 55,000 each of the first tranche and second tranche phantom units. The board of directors of our general partner determined in its discretion that, in light of the service period and performance threshold requirements for vesting of the phantom units, the number of units granted to each of Messrs. Liollo and McGee was adequate to create an incentive for both retention and performance.

Transaction/Transition Grants In September 2010, Messrs. Armstrong, Pefanis and Swanson received the following transaction/transition grants from PAA: Mr. Armstrong, 62,000 each of phantom common units, phantom series A subordinated units and phantom series B subordinated units; Mr. Pefanis, 42,000 each of phantom common units, phantom series A subordinated units and phantom series B subordinated units; and Mr. Swanson, 21,000 each of phantom common units, phantom series A subordinated units and phantom series B subordinated units. Upon vesting, these phantom units will be payable one-for-one by PAA in common units or series A subordinated units of PNG. Decisions with respect to these transaction/transition grant awards were made by the compensation committee of PAA's board of directors, not by our general partner's board. We believe, however, that the vesting terms and number of units involved help to create a meaningful performance incentive to the recipient of the grants, as well as an alignment of interests with our unitholders.

Table of Contents**Employment Agreements**

Mr. Liollo's employment with PAA commenced on November 1, 2008. Pursuant to Mr. Liollo's letter agreement, he is entitled to receive an annual salary of \$250,000. Mr. Liollo's annual target bonus is 225% of his base salary, and he is entitled to participate in our quarterly bonus program. During 2009, Mr. Liollo was paid \$250,000 in the form of salary and approximately \$323,000 in the form of quarterly bonuses. During the second quarter of 2009, Mr. Liollo received an annual bonus of \$250,000 that included a pro rated amount for his 2008/2009 storage season (from commencement of his employment in November 2008 through March 31, 2009). Mr. Liollo received an annual bonus in the second quarter of 2010 for his 2009/2010 storage season service. As a result of his extraordinary efforts in connection with our preparation to become a publicly traded partnership, Mr. Liollo received a special bonus of \$800,000 in January 2010. In connection with his initial employment, Mr. Liollo received a grant of 60,000 phantom units under PAA's long term incentive plan; however, this grant has been replaced by a grant under our Long-Term Incentive Plan. Mr. Liollo's employment agreement has a 36-month term.

Mr. McGee's employment with PAA commenced on September 15, 2009. Pursuant to Mr. McGee's letter agreement, he is entitled to receive an annual salary of \$200,000 and a minimum annual bonus for the first full storage season of \$300,000. Mr. McGee's annual target bonus is 150% of his base salary. During 2009, Mr. McGee was paid approximately \$59,000 in the form of pro-rated salary and he received an annual bonus in the second quarter of 2010 that included a pro rated amount for his 2009/2010 storage season service (from commencement of his employment in September 2009 through March 31, 2010). In connection with his initial employment, Mr. McGee received a grant of 36,000 phantom units under PAA's long term incentive plan; however, this grant has been replaced by a grant under our Long-Term Incentive Plan.

Employment agreements for Messrs. Armstrong and Pefanis are described in PAA's annual report on Form 10-K.

Outstanding Equity Awards at Fiscal Year-End

The following table sets forth certain information with respect to outstanding equity awards at December 31, 2010 with respect to our Named Executive Officers:

Name	Number of Shares or Units of Stock That Have Not Vested (#)	Market Value of Shares or Units of Stock That Have Not Vested (\$)(1)	Unit Awards	
			Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested (#)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested (\$)(1)
Greg L. Armstrong	62,000 ⁽²⁾	1,545,660	62,000 ⁽³⁾ 62,000 ⁽⁴⁾	1,545,660 1,545,660
Harry N. Pefanis	42,000 ⁽²⁾	1,047,060	42,000 ⁽³⁾ 42,000 ⁽⁴⁾	1,047,060 1,047,060
Al Swanson	21,000 ⁽²⁾	523,530	21,000 ⁽³⁾ 21,000 ⁽⁴⁾	523,530 523,530
Dean Liollo			105,000 ⁽⁵⁾	2,617,650

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	105,000 ⁽⁶⁾	2,617,650
	34,375 ⁽⁷⁾	352,886
Richard K. McGee	55,000 ⁽⁵⁾	1,371,150
	55,000 ⁽⁶⁾	1,371,150
	16,500 ⁽⁷⁾	169,385

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- (1) Market value of phantom units and transaction/transition grants reported in these columns is calculated by multiplying the closing market price (\$24.93) of our common units at December 31, 2010 (the last trading day of the fiscal year) by the number of units. No discount is applied for remaining performance threshold or service period requirements. The Class B units are valued based on the grant date fair value computed in accordance with FASB ASC Topic 718 assuming that the highest level of performance conditions will be met.
- (2) These phantom common units will vest 50% on May 5, 2011 and 50% on May 5, 2012, and be payable one-for-one by PAA in Common Units of PNG.
- (3) These phantom series A subordinated units will vest in connection with the conversion of the Series A Subordinated Units into Common Units, and be payable one-for-one by PAA in Common Units of PNG. Any of these phantom series A subordinated units that have not vested as of December 31, 2018 will be automatically cancelled on such date.
- (4) These phantom series B subordinated units will vest in increments of 20%, 21%, 15%, 22% and 22%, respectively, in connection with the conversion of the First through Fifth Tranches of Series B Subordinated Units. Upon vesting, the phantom series B subordinated units will be payable one-for-one by PAA in Series A Subordinated Units or Common Units of PNG it receives upon conversion of the Series B Subordinated Units. Any of these phantom series B subordinated units that have not vested as of December 31, 2018 will be automatically cancelled on such date.
- (5) These first tranche phantom units will vest in one-third increments as follows: one-third will vest upon the later of the May 2012 distribution date and the date on which we pay a quarterly distribution of at least \$0.3875; one-third will vest upon the later of the May 2013 distribution date and the date on which we pay a quarterly distribution of at least \$0.45; and one-third will vest upon the later of the May 2014 distribution date and the date we pay a quarterly distribution of at least \$0.475. The phantom units include tandem distribution equivalent rights that vest (distributions become payable as if the underlying common unit were owned) in 25% increments on the dates we pay a quarterly distribution of \$0.37, \$0.39, \$0.44, and \$0.475, respectively. Any phantom units that have not vested (and all associated DERs) as of the May 2015 distribution date will expire.
- (6) These second tranche phantom units will vest in equal 20% increments as follows: 20% will vest as of the date on which our Series A Subordinated Units convert into Common Units; 20% will vest as of the date on which the first tranche of our Series B Subordinated Units convert into Series A Subordinated Units or Common Units; 20% will vest as of the date on which the second tranche of our Series B Subordinated Units convert into Series A Subordinated Units or Common Units; 20% will vest as of the date on which the third tranche of our Series B Subordinated Units convert into Series A Subordinated Units or Common Units; and 20% will vest as of the date on which the fourth tranche of our Series B Subordinated Units convert into Series A Subordinated Units or Common Units. Conversion of the Series A Subordinated Units and Series B Subordinated Units is subject to certain performance conditions set forth in our partnership agreement. Any of these phantom units that remain outstanding as of January 1, 2018 shall expire without vesting on such date.
- (7) Each Class B unit represents a profits interest in PNGS GP LLC, which entitles the holder to participate in future profits and losses from operations, current distributions from operations, and an interest in future appreciation or depreciation in PNGS GP LLC's asset values, but does not represent an interest in the capital of PNGS GP LLC on the applicable grant date of the Class B units. As of December 31, 2010, none of the Class B units held by Messrs. Liollo and McGee had been earned or vested. For additional information regarding the Class B units, see Item 13. Certain Relationships and Related Transactions, and Director Independence Our General Partner Class B Units of Our General Partner.

Pension Benefits

PAA sponsors a 401(k) plan that is available to all U.S. employees, but neither we nor PAA maintain a pension or defined benefit program.

Table of Contents**Nonqualified Deferred Compensation and Other Nonqualified Deferred Compensation Plans**

Neither we nor PAA have a nonqualified deferred compensation plan or program for our officers or employees.

Potential Payments upon Termination or Change-in-Control

The following table sets forth potential amounts payable to the Dedicated Named Executive Officers upon termination of employment under various circumstances, and as if terminated on December 31, 2010. Information with respect to potential payments to Messrs. Armstrong, Pefanis and Swanson upon termination of employment is contained in PAA's Annual Report on Form 10-K for the year ended December 31, 2010.

	By Reason of	By Reason of	By	By	In
	Death	Disability	Company	Executive	Connection
	(\$)	(\$)	without	with	with a
			Cause	Good	Change
			(\$)	Reason	In Control
				(\$)	(\$)
Dean Liollo					
Salary and Bonus (1)(2)	N/A	N/A	250,000	N/A	1,500,000
Equity Compensation (3)(4)(5)	1,047,060	1,047,060	N/A	N/A	5,235,300
Class B Units (6)	N/A	N/A	N/A	N/A	162,856
Total	1,047,060	1,047,060	250,000	N/A	6,898,156
Richard K. McGee					
Equity Compensation (3)(4)(5)	548,460	548,460	N/A	N/A	2,742,300
Class B Units (6)	N/A	N/A	N/A	N/A	78,169
Total	548,460	548,460	N/A	N/A	2,820,469

- (1) Mr. Liollo's employment agreement provides that if his employment is terminated without cause (as defined below), he is entitled to a lump-sum amount equal to the product of (1) his monthly base salary and (2) twelve. The amount provided in the table assumes a termination date of December 31, 2010, and also assumes a monthly base salary of \$20,833.33.

Mr. Liollo's employment agreement defines "cause" as (i) gross negligence or willful misconduct by Mr. Liollo, (ii) a breach of his confidentiality agreement, or (iii) a misrepresentation of background information and professional credentials. If Mr. Liollo was terminated for cause, Plains All American GP LLC would be obligated to pay his monthly base salary through the date of termination, with no other payment obligations triggered by the termination under the employment agreement or other employment arrangement.

- (2) Pursuant to his employment agreement, if Mr. Liollo's employment is terminated within six months of a change in control (as defined below), he is entitled to a lump-sum payment of \$1,500,000.

For this purpose, a "change in control" is deemed to have occurred on the date when (i) any person (other than PAA or Vulcan Gas Storage or any of their affiliates) becomes the owner, directly or indirectly, of 50.1% or more of the membership interest in PVGS (or its successor or assignee), or (ii) the persons who owned the membership interests in PVGS (or its successor or assignee) on November 1, 2008 cease to beneficially own, directly or indirectly, more than 25% of the membership interest in PVGS in the aggregate.

- (3) The letters evidencing phantom unit grants to Messrs. Liollo and McGee provide that in the event of their death or disability (as defined below), all of their then outstanding phantom units and any associated DERs will be

deemed nonforfeitable, and (i) any unvested phantom units that had satisfied all of the vesting criteria as of the date of their termination but for the passage of time would vest on the next following distribution date and (ii) the remaining unvested outstanding phantom units will vest on the distribution date on which the vesting criteria is met. For this purpose disability means a physical or mental infirmity that impairs the ability substantially to perform duties for a period of eighteen (18) months or that the general partner otherwise determines constitutes a disability.

The dollar value amount provided assumes the death or disability occurred on December 31, 2010. As a result, all phantom units and the associated DERs held by Messrs. Liollo and McGee would have become nonforfeitable effective as of

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December 31, 2010, and vested at the time(s) described in the footnotes to the Outstanding Equity Awards at Fiscal Year-End table. Any units not vested by May 2015 (or January 2018 for the second tranche phantom units) would expire. The dollar value given assumes that all performance thresholds will be timely achieved if deemed probable of occurrence as of December 31, 2010, and is based on the market value of PNG's common units on December 31, 2010 (\$24.93 per unit) without discount for service period. If the performance thresholds were not deemed probable of occurrence as of December 31, 2010, the units are assumed to expire unvested in May 2015 (or January 2018 for the second tranche phantom units). At December 31, 2010, an annualized distribution level of \$1.45, conversion of the series A subordinated units and conversion of the first tranche of series B subordinated units were deemed probable of occurrence. As a result, none of the first tranche phantom unit grants were assumed to eventually vest, and 40% of the second tranche phantom unit grants were assumed to eventually vest.

- (4) Pursuant to the phantom unit grants to Messrs. Liollo and McGee, in the event their employment is terminated other than in connection with a change in control (as defined in Footnote 5 below) or by reason of death, disability (as defined in Footnote 3 above), all of the phantom units and any associated DERs (regardless of vesting) then outstanding under such phantom unit grants would automatically be forfeited as of the date of termination; provided, however, that if their employment is terminated other than for cause (as defined in footnote 5 below), any unvested phantom units that had satisfied all of the vesting criteria as of the date of their termination but for the passage of time would be deemed nonforfeitable and would vest on the next following distribution date. Assuming that Messrs. Liollo and McGee were terminated without cause on December 31, 2010, all of their phantom units would be forfeited.
- (5) The letters evidencing the phantom unit grants to Messrs. Liollo and McGee provide that in the event of a change of status (as defined below), all of the then outstanding phantom units and associated DERs will be deemed nonforfeitable, and such phantom units will vest in full (i.e., the phantom units will become payable in the form of one common unit per phantom unit) upon the next following distribution date. Assuming the change in status occurred on December 31, 2010, all outstanding phantom units and the associated DERs would become nonforfeitable as of such date, and such phantom units would vest on the February 2011 distribution date. The dollar value given is based on the market value of PNG's common units on December 31, 2010 (\$24.93 per unit) without discount for service period.

The phrase "change in status" means, with respect to Messrs. Liollo and McGee, the occurrence, during the period beginning two and a half months prior to and ending one year following a change of control (as defined below), of any of the following: (A) the termination of employment by the general partner other than a termination for cause (as defined below), or (B) the termination of employment by such officer due to the occurrence, without his written consent, of (i) any material diminution in such officer's authority, duties or responsibilities, (ii) any material reduction in such officer's base salary or (iii) any other action or inaction that would constitute a material breach of the agreement by Plains All American GP LLC.

The phrase "change of control" means, and is deemed to have occurred upon the occurrence of, one or more of the following events: (i) PAA ceasing to retain direct or indirect control of our general partner; (ii) any sale, lease, exchange or other transfer (in one transaction or a series of related transactions) of all or substantially all of the assets of PNG or PNGS GP LLC to any person and/or its affiliates, other than to us, PNGS GP LLC or PAA, including any employee benefit plan thereof; (iii) the consolidation, reorganization, merger, or any other similar transaction involving (A) a person other than us, PNGS GP LLC or PAA and (B) us, PNGS GP LLC or both; or (iv) any person, including any partnership, limited partnership, syndicate or other group deemed a person for purposes of Section 13(d) or 14(d) of the Securities Exchange Act of 1934, as amended, becoming the beneficial owner, directly or indirectly, of more than 49.9% of the membership interest in PNGS GP LLC. Notwithstanding the definition of change of control, no change of control is deemed to have occurred in connection with a

restructuring or reorganization related to the securitization and sale to the public of direct or indirect equity interests in our general partner if PAA continues to have the power to elect, directly or indirectly, the majority of the board of directors of our general partner.

The term "cause" means (i) the failure to perform a job function in accordance with standards described in writing, or (ii) the violation of the general partner's Code of Business Conduct (unless waived in accordance with the terms thereof), in each case, with the specific failure or violation described in writing.

- (6) Pursuant to the Class B Restricted Units Agreements, upon the occurrence of a Change in Control (defined below), any earned Class B units (and any Class B units that will become earned in less than 180 days) become vested units and, to the extent any Class B units remain unearned, an incremental 25% of the number of Class B units originally granted becomes vested. As

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of December 31, 2010, none of the Class B units held by Messrs. Liollo or McGee had been earned or will become earned in less than 180 days. Assuming a Change in Control on December 31, 2010, 25% of the Class B units held by Messrs. Liollo and McGee would become vested. The value of such Class B units as reflected in the table is derived in accordance with FASB ASC Topic 718. Change in Control means the determination by the Board that one of the following events has occurred: (i) PNGS GP LLC ceases to retain direct or indirect control over the Partnership; (ii) PAA and its affiliates (the Owner Affiliates) cease to own directly or indirectly at least 50% of the member interests of PNGS GP LLC; (iii) a person or group (as such terms are used in Sections 13(d) and 14(d) of the Exchange Act) becomes after the Grant Date the beneficial owner (as defined in Rules 13(d)-3 and 13(d)-5 under the Exchange Act), directly or indirectly, of more than 50% of the member interest of PNGS GP LLC; or (iv) a transfer, sale, exchange or other disposition in a single transaction or series of transactions (whether by merger or otherwise) of all or substantially all of the assets of PNGS GP LLC or the Partnership to one or more persons who are not Affiliates of PNGS GP LLC, other than a transaction in which the Owner Affiliates become the beneficial owners, directly or indirectly, of more than 50% of the voting power of such person or persons immediately following such transaction.

Confidentiality, Non-Compete and Non-Solicitation Arrangements

Pursuant to their employment agreements, Messrs. Liollo and McGee have agreed to maintain the confidentiality of PAA and PNG information for a period of two years after the termination of their employment. They have also agreed not to solicit customers or employees for a period of two years following termination of their employment.

Table of Contents**Compensation of Directors**

The following table sets forth a summary of the compensation paid to each person who served as a non-employee director of our general partner in 2010:

Name	Fees	Stock	Total (\$)
	Earned or Paid in Cash (\$)	Awards (\$)⁽¹⁾	
Victor Burk	32,500 ⁽²⁾	369,416	401,916
Bobby S. Shackouls	27,500 ⁽²⁾	369,416	396,916
Arthur L. Smith	(3)		

(1) The dollar value of LTIPs granted during 2010 is based on the grant date fair value computed in accordance with FASB ASC Topic 718. In connection with the August 2010 vesting of director LTIP awards, Messrs. Burk and Shackouls each were granted 938 units by virtue of the automatic re-grant feature of the vested awards. In addition to the automatic re-grant in August, Messrs. Burk and Shackouls each also received an initial grant of 15,000 LTIPs in May 2010.

(2) Messrs. Burk and Shackouls joined the board in April 2010 in connection with our initial public offering. Fees earned or paid reflect a partial year of service.

(3) Mr. Smith joined the board in December 2010. He was not paid any compensation in 2010.

Each director of PNGS GP LLC who is not an employee of Plains All American GP LLC is reimbursed for any travel, lodging and other out-of-pocket expenses related to meeting attendance or otherwise related to service on the board (including, without limitation, reimbursement for continuing education expenses). Each non-employee director is paid an annual retainer fee of \$40,000. Messrs. Armstrong, Pefanis, Swanson and Liollo are otherwise compensated for their services as employees and therefore receive no separate compensation for their services as directors. In addition to the annual retainer, the chairman of the audit committee receives \$25,000 annually, and the other members of the audit committee receive \$15,000 annually, in each case, in addition to the annual retainer. During 2010, Mr. Burk served as chairman of the audit committee.

Our non-employee directors receive LTIP awards as part of their compensation. The LTIP awards vest annually in 25% increments over a four-year period and have an automatic re-grant feature such that as they vest, an equivalent amount is granted. The awards have associated distribution equivalent rights that are payable quarterly.

All LTIP awards held by a director vest in full upon the next following distribution date after the death or disability (as determined in good faith by the board) of the director. The awards also vest in full if such director (i) retires (no longer with full-time employment and no longer serving as an officer or director of any public company) or (ii) is removed from the board of directors or is not reelected to the board of directors, unless such removal or failure to reelect is for good cause, as defined in the letter granting the units.

Each director will be indemnified for his actions associated with being a director to the fullest extent permitted under Delaware law.

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

Our common units and series A and series B subordinated units outstanding represent 98% of our equity (limited partner interest). The 2% general partner interest and all of our incentive distribution rights are owned by our general partner, PNGS GP LLC. The following table sets forth the beneficial ownership of limited partner units held by beneficial owners of 5% or more of the units, directors, the Named Executive Officers, and all directors and executive officers as a group as of February 28, 2011.

Name of Beneficial Owner	Common Units	Percentage of		Percentage of		Percentage of	
		Common Units	Series A Subordinated Units	Series A Subordinated Units	Series B Subordinated Units	Series B Subordinated Units	Common and Series B Subordinated Units
Plains All American Pipeline, L.P. 333 Clay Street, Suite 1600 Houston, TX 77002	28,272,870	47.8%	11,934,351	100%	13,500,000	100%	63.5%
Richard A. Kayne/Kayne Anderson Capital Advisors, L.P. 1800 Avenue of the Stars Second Floor Los Angeles, CA 90067	5,207,497 ⁽¹⁾	8.8%					6.2%
Greg L. Armstrong	100,000 ⁽²⁾⁽³⁾	*					*
Harry N. Pefanis	65,000 ⁽²⁾	*					*
Al Swanson	37,500 ⁽²⁾	*					*
Dean Liollo	26,700 ⁽⁴⁾	*					*
Richard K. McGee	20,000 ⁽⁴⁾	*					*
Victor Burk	1,938	*					*
Bobby S. Shackouls	938	*					*
Arthur L. Smith							
All directors and executive officers as a group (9 persons)	252,076 ⁽⁵⁾	*					*

* Less than 1%

- (1) This information has been derived from a Schedule 13G filed with the SEC on February 14, 2011. Based on the information contained in the filing, Kayne Anderson Capital Advisors, L.P. and Richard A. Kayne have shared voting power and dispositive power with respect to, and beneficially own, an aggregate of 5,196,497 common units. Mr. Kayne has sole voting power and dispositive power with respect to, and beneficially owns, 11,000 common units.
- (2) Does not include unvested phantom units under transaction/transition grants, none of which will vest within 60 days of the date hereof. See Item 11. Executive Compensation Outstanding Equity Awards at Fiscal Year-End.

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- (3) Does not include common and subordinated units owned by Plains All American Pipeline, L.P. Mr. Armstrong is Chairman of the Board, Chief Executive Officer and a Director of PAA's general partner. He disclaims any beneficial ownership of PAA's interest in PNG.
- (4) Does not include unvested phantom units granted under our Long-Term Incentive Plan, none of which will vest within 60 days of the date hereof. See Item 11. Executive Compensation Outstanding Equity Awards at Fiscal Year-End.
- (5) As of February 28, 2011, no units were pledged by directors or Named Executive Officers. Certain of the directors and Named Executive Officers hold units in marginable broker's accounts, but none of the units were margined as of February 28, 2011.

Equity Compensation Plan Information

The following table sets forth certain information with respect to our equity compensation plans as of December 31, 2010. For a description of these plans, see Item 13. Certain Relationships and Related Transactions, and Director Independence Our General Partner Equity-Based Long-Term Incentive Plan.

Plan Category	Number of Units to be Issued upon Exercise/Vesting of Outstanding Options, Warrants and Rights (a)	Weighted Average Exercise Price of Outstanding Options, Warrants and Rights (b)	Number of Units Remaining Available for Future Issuance under Equity Compensation Plans (c)
Equity compensation plans approved by unitholders:			
Long Term Incentive Plan	610,000 ⁽¹⁾	N/A ⁽²⁾	2,388,124 ⁽¹⁾⁽³⁾
Equity compensation plans not approved by unitholders:			
N/A			

- (1) The Long Term Incentive Plan was approved by our unitholders in April 2010. The LTIP contemplates the issuance or delivery of up to 3,000,000 units to satisfy awards under the plan. The number of units presented in column (a) assumes that all outstanding grants will be satisfied by the issuance of new units upon vesting unless such LTIPs are by their terms payable only in cash. In fact, some portion of the phantom units may be settled in cash and some portion will be withheld for taxes. Any units not issued upon vesting will become available for future issuance under column (c).
- (2) Phantom unit awards under the LTIP vest without payment by recipients.
- (3) In accordance with Item 201(d) of Regulation S-K, column (c) excludes the securities disclosed in column (a). However, as discussed in footnote (1), any phantom units represented in column (a) that are not satisfied by the issuance of units become available for future issuance.

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

For a discussion of director independence, see Item 10. Directors and Executive Officers of Our General Partner and Corporate Governance.

Our General Partner

Our operations and activities are managed by our general partner. The officers of our general partner are employed by PAA's general partner and manage the day-to-day affairs of our business. Certain of our officers devote a substantial portion of their time to managing our business, while other officers have responsibilities for both us and PAA. We also utilize a significant number of employees of PAA's general partner to operate our business and provide us with general and administrative services. We reimburse PAA for all expenses incurred on our behalf (other than expenses related to the Class B units of our general partner). Total costs reimbursed by us to PAA for the year ended December 31, 2010 were approximately \$19.5 million.

Our general partner owns the 2% general partner interest and all of the incentive distribution rights. Our general partner is entitled to receive incentive distributions if the amount we distribute with respect to any quarter exceeds levels specified in our partnership agreement. Under the quarterly incentive distribution provisions, generally our general partner is entitled, without duplication, to 15% of amounts we distribute in excess of \$0.3375 (\$1.35 annualized) per unit, 25% of the amounts we distribute in excess of \$0.37125 (\$1.485 annualized) per unit and 50% of amounts we distribute in excess of \$0.50625 (\$2.025 annualized) per unit.

The following table illustrates the allocation of aggregate distributions at different per-unit levels (dollars in thousands):

Annual LP Distribution Per Unit	Distribution to LP Unitholders⁽¹⁾	Distribution to GP⁽¹⁾⁽²⁾	Total Distribution⁽¹⁾⁽²⁾	GP % of Total Distribution
\$1.35	\$ 96,010	\$ 1,959	\$ 97,969	2.0%
\$1.40	\$ 99,566	\$ 2,587	\$ 102,153	2.5%
\$1.45	\$103,122	\$ 3,214	\$ 106,336	3.0%
\$1.50	\$106,678	\$ 4,009	\$ 110,687	3.6%
\$1.55	\$110,234	\$ 5,195	\$ 115,429	4.5%
\$1.60	\$113,790	\$ 6,380	\$ 120,170	5.3%
\$1.65	\$117,346	\$ 7,565	\$ 124,911	6.1%

(1) Based on 71,118,801 Common Units and Series A Subordinated Units outstanding at February 28, 2011. Does not include Series B Subordinated Units. An increase in the number of units outstanding would increase both the distribution to unitholders and the distribution to the general partner for any given level of distribution per unit.

(2) Includes distributions attributable to the 2% general partner interest and the incentive distribution rights.

Equity-Based Long-Term Incentive Plan

In April 2010, our general partner adopted the PAA Natural Gas Storage, L.P. 2010 Long Term Incentive Plan for the employees, directors and consultants of our general partner and its affiliates, including PAA, who perform services for us. Awards contemplated under the Plan include restricted units, phantom units, unit options, unit appreciation rights, unit awards and deferred common units. The Long Term Incentive Plan limits the number of common units that may be delivered pursuant to awards under the plan to 3,000,000 units. Units forfeited or withheld to satisfy tax withholding obligations will again become available for delivery pursuant to other awards. In addition, if an award is forfeited, canceled or otherwise terminates, expires or is settled without the delivery of units, the units subject to such award will again be available for new awards under the Long Term Incentive Plan. Common units to be delivered pursuant to awards under the Long Term Incentive Plan may be newly issued common units, common units acquired by us in the open market, common units acquired by us from any other person, or any combination of the foregoing. If we issue new common units upon vesting of the phantom units, the total number of common units outstanding will increase.

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Administration. The Long Term Incentive Plan is administered by the board of directors of our general partner. The board of directors of our general partner may terminate or amend the Long Term Incentive Plan at any time with respect to any units for which a grant has not yet been made. Our board of directors also has the right to alter or amend the Long Term Incentive Plan or any part of the Long Term Incentive Plan from time to time, including increasing the number of units that may be granted, subject to unitholder approval as may be required by the exchange upon which the common units are listed at that time, if any. No change may be made in any outstanding grant that would materially reduce the benefits of the participant without the consent of the participant. The Long Term Incentive Plan will expire upon its termination by the board of directors or, if earlier, when no units remain available under the Long Term Incentive Plan for awards. Upon termination of the Long Term Incentive Plan, awards then outstanding will continue pursuant to the terms of their grants.

Phantom Units. A phantom unit entitles the grantee to receive a common unit upon the vesting of the phantom unit or, in the discretion of the plan administrator, cash equivalent to the value of a common unit. The plan administrator determines to make grants of phantom units under the Long Term Incentive Plan containing such terms as the plan administrator determines.

The plan administrator, in its discretion, may grant distribution equivalent rights, which we refer to as DERs, with respect to a phantom unit. DERs entitle the grantee to receive a cash payment equal to the cash distributions made on a common unit during the period the phantom unit is outstanding. The plan administrator will establish whether the DERs are paid currently, when the tandem phantom unit vests or on some other basis.

The issuance of common units upon vesting of the phantom units under the Long Term Incentive Plan is intended primarily to serve as a means of incentive compensation for performance and not primarily as an opportunity to participate in the equity appreciation of our common units. Therefore, plan participants will not pay any consideration for the common units they receive and we will receive no remuneration for the units.

Other Awards. The Long Term Incentive Plan also permits the grant of restricted units, unit options, unit appreciation rights and unit awards. No such awards have been granted to date.

Deferred Awards. Awards granted under the Long Term Incentive Plan may be deferred to the extent permitted by the plan administrator in its discretion. The plan administrator may, for example, determine to make grants of deferred common units, which would vest immediately upon issuance and be delivered to the holder upon termination or retirement from our general partner or upon some later date that is selected by the participant or the plan administrator in accordance with Section 409A of the Internal Revenue Code. Deferred common units would typically receive all cash or other distributions paid by us on account of our common units.

Class B Units of Our General Partner

Our general partner has authorized the issuance to members of our management team Class B units, each representing a profits interest in our general partner. The Class B units are limited to proportionate participation in cash distributions paid by our general partner above specified quarterly distribution levels.

The cost of the obligations represented by the Class B units is borne solely by our general partner. We are not obligated to reimburse our general partner for such costs and any distributions made on such Class B units will not reduce the amount of cash available for distribution to our unitholders. Under generally accepted accounting principles, however, the Class B units represent an equity compensation plan for our benefit. Accordingly, once the likelihood of achievement of a performance threshold is considered probable, we will record an expense related to the fair market value of the associated interest at the date of grant, proportionate to the relevant service period incurred through such date. Any balance will be amortized over the remaining service period through the achievement of such performance threshold. An offsetting entry will be recorded to partners' capital to reflect a capital contribution from our general partner equal to the amount recorded as expense in our financial statements.

As of December 31, 2010, 90,750 Class B units were issued and outstanding out of 165,000 authorized. The outstanding Class B units are subject to restrictions on transfer and generally become earned (entitled to participate in distributions) in percentage increments when the annualized quarterly distributions on our common units equal or exceed certain thresholds. Class B units become earned in 25% increments 180 days after we pay annualized quarterly distributions on our common units of \$2.00, \$2.30, \$2.50 and \$2.70. Earned Class B units will be entitled to their proportionate share of all quarterly cash distributions made by

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our general partner in excess of \$2.5 million per quarter. Fifty percent of earned units will vest immediately upon becoming earned and 50% will vest on the fifth anniversary of the date of grant. Any Class B units that are earned after the fifth anniversary of the date of grant will fully vest upon becoming earned. Assuming all authorized Class B units are issued, the maximum participation would be 6% of the amount in excess of \$2.5 million per quarter. As of December 31, 2010, none of the Class B units had been earned.

To encourage retention following achievement of these performance benchmarks, Class B units remain forfeitable (whether or not earned) if the holder terminates his employment prior to May 5, 2015. Additionally, the participation amount is capped to the maximum amount paid at the time of termination of employment, such that the holder does not benefit from growth in cash distributions experienced after the holder's employment terminates. Upon the occurrence of a change of control (as defined), (i) all earned units will vest, and (ii) to the extent any of the units are unearned at the time, an incremental 25% of the units originally awarded will vest. All earned Class B units will also vest if they remain outstanding as of May 5, 2015.

Related Party Transactions***Omnibus Agreement***

In May 2010, we entered into an omnibus agreement with PAA and certain of its affiliates, pursuant to which we agreed upon certain aspects of our relationship with PAA, including, among other things (1) the provision by PAA's general partner to us of certain general and administrative services and our agreement to reimburse PAA's general partner for such services, (2) the provision by PAA's general partner of such personnel as may be necessary to operate and manage our business, and our agreement to reimburse PAA's general partner for the expenses associated with such personnel, (3) certain indemnification obligations, and (4) our use of the name PAA and related marks. Under this agreement, PAA indemnifies us against certain environmental liabilities, tax matters, and title or permitting defects generally for a period of three years after the closing of our initial public offering. The environmental indemnifications are subject to a cap of \$15 million and require us to pay the first \$250,000 of costs incurred. In addition, we have indemnified PAA against any losses, costs or damages incurred by PAA or its general partner that are attributable to the ownership and operation of our assets following the closing of our initial public offering.

Tax Sharing Agreement

In May 2010, we entered into a tax sharing agreement with PAA, pursuant to which we and PAA agreed on the method of allocation among us and our subsidiaries, on the one hand, and PAA and its subsidiaries (other than us and our subsidiaries) on the other, of the responsibilities, liabilities and benefits relating to any taxes for which a combined return is filed for taxable periods including or beginning on the closing date of our IPO.

Potential PAA Financial Support

PAA may elect, but is not obligated, to provide financial support to us under certain circumstances, such as in connection with an acquisition or expansion capital project. Our partnership agreement contains provisions designed to facilitate PAA's ability to provide us with financial support while reducing concerns regarding conflicts of interest by defining certain potential financing transactions between PAA and us as fair to our unitholders. As further defined in our partnership agreement, potential PAA financial support can include, but is not limited to, our issuance of common units to PAA, our borrowing of funds from PAA or guaranties or trade credit support to support the ongoing operations of us or our subsidiaries. We have no obligation to seek financing or support from PAA or to accept such financing or support if offered to us.

Private Placement

In February 2011, in connection with our Southern Pines Acquisition, we completed a private placement of approximately 17.4 million common units to various third-party investors for net proceeds of approximately \$370 million, and the sale of approximately 10.2 million common units to PAA for net proceeds of approximately \$230 million, including PAA's proportionate 2% general partner contribution of \$12 million.

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Intercompany Notes with PAA

In September 2009, we entered into a related party note payable to PAA with a fixed interest rate of 6.5%. In May 2010, we used the net proceeds from our initial public offering, together with borrowings under our credit facility, to repay approximately \$468.4 million of the intercompany note. The remaining balance of \$16.4 million was extinguished and treated as a capital contribution and part of PAA's investment in us.

In February 2011, in connection with our Southern Pines Acquisition, PAA provided debt financing to us in the form of a \$200 million three-year senior unsecured loan that bears interest at 5.25%.

Contracts with Affiliates

In December 2008, PAA advanced \$600,000 to Dean Liollo, President of our general partner, to assist him with the payment of relocation expenses incurred in connection with his employment. The advance, which did not bear any interest, was repaid in full prior to our IPO.

Sale of Land for PAA Natural Gas Processing Plant

In January 2011, we sold an approximately 30 acre parcel of vacant, unused land located in Acadia Parish, Louisiana to a subsidiary of PAA to be used for the potential development of a natural gas processing plant. The sales price of approximately \$72,000 was based on a third party appraisal and the sale was made on an as is, where is basis without any representations or warranties by us.

Review, Approval or Ratification of Transactions with Related Persons

We have adopted policies for the review, approval and ratification of transactions with related persons similar to those that have been adopted by PAA. Pursuant to our Governance Guidelines, a director is expected to bring to the attention of the CEO or the board any conflict or potential conflict of interest that may arise between the director or any affiliate of the director, on the one hand, and the Partnership or our general partner on the other. The resolution of any such conflict or potential conflict should, at the discretion of the board in light of the circumstances, be determined by a majority of the disinterested directors.

If a conflict or potential conflict of interest arises between the Partnership and our general partner, the resolution of any such conflict or potential conflict should be addressed by the board in accordance with the provisions of the Partnership Agreement. At the discretion of the board in light of the circumstances, the resolution may be determined by the board in its entirety or by a conflicts committee meeting the definitional requirements for such a committee under the Partnership Agreement.

Pursuant to our Code of Business Conduct, any executive officer must avoid conflicts of interest unless approved by the board of directors.

In the case of any sale of equity by the Partnership in which an owner or affiliate of an owner of our general partner participates, our practice is to obtain approval of the board for the transaction. The board will typically delegate authority to set the specific terms to a pricing committee, consisting of the CEO and one independent director. Actions by the pricing committee require unanimous approval.

Table of Contents**Item 14. Principal Accountant Fees and Services**

The following table details the aggregate fees billed for professional services rendered by our independent auditor (in millions):

	Year Ended December 31, 2010
Audit fees ⁽¹⁾	\$ 0.5
Audit-related fees	0.0
Tax fees ⁽²⁾	0.1
All other fees	0.0
Total	\$ 0.6

(1) Audit fees include those related to our annual audit (including internal control evaluation and reporting) and work performed on our initial public offering.

(2) Tax fees are for tax processing as well as the preparation of Forms K-1 for our unitholders.

Pre-Approval Policy

All services provided by our independent auditor are subject to pre-approval by our audit committee. The audit committee has instituted a policy that describes certain pre-approved non-audit services. We believe that the description of services is designed to be sufficiently detailed as to particular services provided, such that (i) management is not required to exercise judgment as to whether a proposed service fits within the description and (ii) the audit committee knows what services it is being asked to pre-approve. The audit committee is informed of each engagement of the independent auditor to provide services under the policy. All services provided by our independent auditor during the year ended December 31, 2010 were approved in advance by our audit committee.

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PART IV

Item 15. Exhibits and Financial Statement Schedules

(a) (1) Financial Statements

See Index to the Consolidated Financial Statements set forth on Page F-1.

(2) Financial Statement Schedules

All schedules are omitted because they are either not applicable or the required information is shown in the consolidated financial statements or notes thereto.

(3) Exhibits

- 2.1 Purchase and Sale Agreement dated December 28, 2010 by and among SGR Holdings, L.L.C., Southern Pines Energy Investment Co., LLC and PAA Natural Gas Storage, L.P. (incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K filed on December 30, 2010).
- 3.1 Certificate of Limited Partnership of PAA Natural Gas Storage, L.P. (incorporated by reference to Exhibit 3.1 to the Registration Statement on Form S-1 (333-164492) filed on January 25, 2010).
- 3.2 Second Amended and Restated Agreement of Limited Partnership of PAA Natural Gas Storage, L.P. dated August 16, 2010 (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed on August 20, 2010).
- 3.3 Certificate of Formation of PNGS GP LLC (incorporated by reference to Exhibit 3.3 to the Registration Statement on Form S-1 (333-164492) filed on January 25, 2010).
- 3.4 Amended and Restated Limited Liability Company Agreement of PNGS GP LLC dated May 5, 2010 (incorporated by reference to Exhibit 3.4 to the Quarterly Report on Form 10-Q filed on August 6, 2010).
- 4.1 Form of Registration Rights Agreement by and among PAA Natural Gas Storage, L.P. and the purchasers party thereto (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed on December 30, 2010).
- 4.2 Form of Registration Rights Agreement by and among PAA Natural Gas Storage, L.P. and the purchasers party thereto (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed on January 20, 2011).
- 10.1 Contribution Agreement dated as of April 29, 2010 by and among PAA Natural Gas Storage, L.P., PNGS GP LLC, Plains All American Pipeline, L.P., PAA Natural Gas Storage, LLC, PAA/Vulcan Gas Storage, LLC, Plains Marketing, L.P. and Plains Marketing GP Inc. (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed on May 4, 2010).
- 10.2 Omnibus Agreement dated May 5, 2010 by and among Plains All American GP LLC, Plains All American Pipeline, L.P., PNGS GP LLC and PAA Natural Gas Storage, L.P. (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed on May 11, 2010).
- 10.3 Tax Sharing Agreement dated May 5, 2010 by and among Plains All American Pipeline, L.P. and PAA Natural Gas Storage, L.P. (incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K filed on May 11, 2010).

- 10.4 Credit Agreement dated April 7, 2010 among PAA Natural Gas Storage, L.P., Bank of America, N.A., DnB Nor Bank ASA, Wells Fargo Bank, National Association, UBS Loan Finance LLC and Citibank, N.A. and the other lenders party thereto (incorporated by reference to Exhibit 10.4 to the Current Report on Form 8-K filed May 11, 2010).
- 10.5 Employment Agreement, effective November 1, 2008, between Dean Liollo and Plains All American GP LLC (incorporated by reference to Exhibit 10.10 to Amendment No. 3 to the Registration Statement on Form S-1 (333-164492) filed on April 13, 2010).

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- 10.6 Employment Agreement, effective September 15, 2009, between Richard McGee and Plains All American GP LLC (incorporated by reference to Exhibit 10.9 to Amendment No. 3 to the Registration Statement on Form S-1 (333-164492) filed on April 13, 2010).
- 10.7 PAA Natural Gas Storage, L.P. 2010 Long Term Incentive Plan (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed on May 11, 2010).
- 10.8 Form of Phantom Unit and Distribution Equivalent Right Grant Letter (incorporated by reference to Exhibit 10.4 to Amendment No. 3 to the Registration Statement on Form S-1 (333-164492) filed on April 13, 2010).
- 10.9 Form of Phantom Unit Grant Letter (incorporated by reference to Exhibit 10.9 to the Quarterly Report on Form 10-Q filed on November 5, 2010).
- 10.10 Form of PNGS GP LLC Class B Restricted Unit Agreement (incorporated by reference to Exhibit 10.10 to the Quarterly Report on Form 10-Q filed on August 6, 2010).
- 10.11 Common Unit Purchase Agreement dated December 23, 2010 by and among PAA Natural Gas Storage, L.P. and the purchasers party thereto (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed on December 30, 2010).
- 10.12 Common Unit Purchase Agreement dated January 19, 2011 by and among PAA Natural Gas Storage, L.P. and the purchasers party thereto (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed on January 20, 2011).
- 10.13 Note Payable to PAA dated February 9, 2011 (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed on February 14, 2011).
- 10.14 Agreement to Lease with Option to Purchase, dated May 1, 2006, between Industrial Development Board No. 1 of the Parish of Evangeline State of Louisiana, Inc. and Pine Prairie Energy Center, LLC (incorporated by reference to Exhibit 10.7 to Amendment No. 2 to the Registration Statement on Form S-1 (333-164492) filed on April 2, 2010).
- 10.15 * Director Compensation Summary.
- 21.1* List of Subsidiaries of PAA Natural Gas Storage, L.P.
- 23.1* Consent of PricewaterhouseCoopers LLP.
- 23.2* Consent of PricewaterhouseCoopers LLP.
- 31.1* Certification of Principal Executive Officer pursuant to Exchange Act Rules 13a-14(a) and 15d-14(a).
- 31.2* Certification of Principal Financial Officer pursuant to Exchange Act Rules 13a-14(a) and 15d-14(a).
- 32.1* Certification of Principal Executive Officer pursuant to 18 U.S.C. 1350.

32.2* Certification of Principal Financial Officer pursuant to 18 U.S.C. 1350.

Management compensatory plan or arrangement.

* Filed herewith.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

PAA NATURAL GAS STORAGE, L.P.

By: PNGS GP LLC, its general partner

Date: March 2, 2011

By: /s/ Greg L. Armstrong

Name: Greg L. Armstrong

Title: Chairman and Chief Executive Officer
(Principal Executive Officer)

Date: March 2, 2011

By: /s/ Dean Liollo

Name: Dean Liollo

Title: President

Date: March 2, 2011

By: /s/ Al Swanson

Name: Al Swanson

Title: Senior Vice President and
Chief Financial Officer
(Principal Financial Officer)

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

Name	Title	Date
/s/ Greg L. Armstrong Greg L. Armstrong	Chairman of the Board, Chief Executive Officer and Director of PNGS GP LLC (Principal Executive Officer)	March 2, 2011
/s/ Dean Liollo Dean Liollo	President and Director of PNGS GP LLC	March 2, 2011
/s/ Al Swanson Al Swanson	Senior Vice President, Chief Financial Officer and Director of PNGS GP LLC (Principal Financial Officer)	March 2, 2011
/s/ Donald C. O Shea Donald C. O Shea	Controller and Chief Accounting Officer of PNGS GP LLC (Principal Accounting Officer)	March 2, 2011
/s/ Harry N. Pefanis Harry N. Pefanis	Vice Chairman and Director of PNGS GP LLC	March 2, 2011
/s/ Victor Burk Victor Burk	Director of PNGS GP LLC	March 2, 2011
/s/ Bobby S. Shackouls Bobby S. Shackouls	Director of PNGS GP LLC	March 2, 2011
/s/ Arthur L. Smith Arthur L. Smith	Director of PNGS GP LLC	March 2, 2011

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**PAA NATURAL GAS STORAGE, L.P. AND SUBSIDIARIES
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MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

PAA Natural Gas Storage, L.P.'s management is responsible for establishing and maintaining adequate internal control over financial reporting. Our internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Internal control over financial reporting cannot provide absolute assurance of achieving financial reporting objectives because of its inherent limitations. Internal control over financial reporting is a process that involves human diligence and compliance and is subject to lapses in judgment and breakdowns resulting from human failures. Internal control over financial reporting also can be circumvented by collusion or improper management override. Because of such limitations, there is a risk that material misstatements may not be prevented or detected on a timely basis by internal control over financial reporting. However, these inherent limitations are known features of the financial reporting process. Therefore, it is possible to design into the process safeguards to reduce, though not eliminate, this risk.

Management has used the framework set forth in the report entitled *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) to evaluate the effectiveness of the Partnership's internal control over financial reporting. Based on that evaluation, management has concluded that the Partnership's internal control over financial reporting was effective as of December 31, 2010.

The effectiveness of the Partnership's internal control over financial reporting as of December 31, 2010 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears on Page F-3.

/s/ GREG L. ARMSTRONG
Greg L. Armstrong
*Chairman of the Board, Chief Executive
Officer and Director of PNGS GP LLC
(Principal Executive Officer)*

/s/ AL SWANSON
Al Swanson
*Senior Vice President and Chief Financial
Officer of PNGS GP LLC
(Principal Financial Officer)*

February 25, 2011

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Report of Independent Registered Public Accounting Firm

To the Board of Directors of the General Partner and Unitholders of
PAA Natural Gas Storage, L.P.:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of operations, of changes in partners' capital and members' capital, and of cash flows present fairly, in all material respects, the financial position of PAA Natural Gas Storage, L.P. and its subsidiaries (successor) at December 31, 2010 and 2009, and the results of their operations and their cash flows for the year ended December 31, 2010 and the period from September 3, 2009 through December 31, 2009, in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2010, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Partnership's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express opinions on these financial statements and on the Partnership's internal control over financial reporting based on our audit, which was an integrated audit in 2010. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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

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

Houston, Texas
March 2, 2011

PricewaterhouseCoopers LLP

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Report of Independent Registered Public Accounting Firm

To the Board of Directors of the General Partner and Unitholders of
PAA Natural Gas Storage, L.P.:

In our opinion, the accompanying consolidated statements of operations, of changes in partners' capital and members' capital and of cash flows of PAA Natural Gas Storage, L.P. and its subsidiaries (predecessor) present fairly, in all material respects, the results of their operations and their cash flows for the period from January 1, 2009 through September 2, 2009, and the year ended December 31, 2008 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

Houston, Texas
January 22, 2010

PricewaterhouseCoopers LLP

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PAA NATURAL GAS STORAGE, L.P. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(in thousands, except unit amounts)

	December 31, 2010	December 31, 2009
ASSETS		
Current assets		
Cash and cash equivalents	\$ 346	\$ 3,124
Restricted cash	20,000	
Accounts receivable	12,786	6,439
Natural gas imbalance receivables	1,200	400
Other current assets	1,544	2,280
Total current assets	35,876	12,243
Property and equipment		
Property and equipment	892,645	816,267
Less: Accumulated depreciation, depletion and amortization	(14,837)	(3,004)
Property and equipment, net	877,808	813,263
Other assets		
Base gas	37,498	27,927
Goodwill and intangibles, net	47,546	46,974
Total other assets, net	85,044	74,901
Total assets	\$ 998,728	\$ 900,407
LIABILITIES, PARTNERS CAPITAL AND MEMBERS CAPITAL		
Current liabilities		
Accounts payable and accrued liabilities	\$ 12,806	\$ 14,034
Natural gas imbalance payables	1,200	400
Accrued income and other taxes	1,009	1,610
Total current liabilities	15,015	16,044
Long-term liabilities		
Note payable to PAA		450,523
Long-term debt under credit facility	259,900	
Other long-term liabilities	423	1,096
Total long-term liabilities	260,323	451,619
Total liabilities	275,338	467,663
Commitments and contingencies (Note 11)		
Partners capital and members capital		

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Common unitholders (31,586,405 units issued and outstanding at December 31, 2010)	474,489	
Subordinated unitholders (25,434,351 units issued and outstanding at December 31, 2010)	236,853	
General partner	13,637	
Members' capital		432,744
Accumulated other comprehensive loss	(1,589)	
Total partners' capital and members' capital	723,390	432,744
Total liabilities, partners' capital and members' capital	\$ 998,728	\$ 900,407

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

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PAA NATURAL GAS STORAGE, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(in thousands, except per unit data)

	Year Ended December 31, 2010	Successor September 3, 2009 through December 31, 2009 (See Note 1)	Predecessor January 1, 2009 through September 2, 2009 (See Note 1)	Year Ended December 31, 2008
Revenues				
Firm storage services	\$ 90,965	\$ 23,972	\$ 42,649	\$ 42,871
Hub services	6,190	1,637	2,988	1,417
Other	3,132	(358)	1,292	4,889
Total revenues	100,287	25,251	46,929	49,177
Costs and expenses				
Storage related costs	23,465	7,003	8,792	8,934
Other operating costs (except those shown below)	7,242	3,257	4,820	4,059
Fuel expense	2,368	578	1,816	2,320
General and administrative expenses	15,965	4,083	3,562	3,874
Depreciation, depletion and amortization	14,119	3,578	8,054	6,245
Total costs and expenses	63,159	18,499	27,044	25,432
Operating income	37,128	6,752	19,885	23,745
Other income/(expense)				
Interest expense, net of capitalized interest	(7,323)	(4,262)	(4,352)	(4,941)
Interest income	2		139	1,147
Income tax expense			(473)	(887)
Gain on interest rate swaps			336	548
Other income (expense)	(20)	(2)	(17)	(26)
Net income	\$ 29,787	\$ 2,488	\$ 15,518	\$ 19,586
Calculation of Limited Partner Interest in Net Income: ⁽¹⁾				
Net income	\$ 24,359	n/a	n/a	n/a
Less general partner interest in net income	537	n/a	n/a	n/a
Limited partner interest in net income	\$ 23,822	n/a	n/a	n/a

Net income per limited partner unit (basic and diluted) ⁽¹⁾

Common and Series A subordinated units ⁽²⁾	\$ 0.54	n/a	n/a	n/a
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Limited partner units outstanding ⁽¹⁾

Common and Series A subordinated units ⁽²⁾ (Basic)	44,375	n/a	n/a	n/a
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Common and Series A subordinated units ⁽²⁾ (Diluted)	44,383	n/a	n/a	n/a
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(1) Reflective of general and limited partner interest in net income since closing of the Partnership's initial public offering. See Note 2, Net Income per Limited Partner Unit.

(2) Excludes Series B subordinated units. See Note 2, Net Income per Limited Partner Unit.

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

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PAA NATURAL GAS STORAGE, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN PARTNERS' CAPITAL AND MEMBERS' CAPITAL
(in thousands)

	Members Capital	Common	Partners Limited Partners Subordinated Series A	Capital Series B	General Partner	Accumulated Other Comprehensive Loss	Total
Predecessor							
Balance at December 31, 2007	\$ 300,715	\$	\$	\$	\$	\$ (5,998)	\$294,717
Net income	19,586						19,586
Contributions from members	74,500						74,500
Distributions to members	(14,500)						(14,500)
Net derivative gain/loss on cash flow hedges						(11,073)	(11,073)
Balance at December 31, 2008	\$ 380,301	\$	\$	\$	\$	\$ (17,071)	\$363,230
Net income	15,518						15,518
Contributions from members	8,500						8,500
Distributions to members	(8,500)						(8,500)
Net derivative gain/loss on cash flow hedges						1,990	1,990
Balance at September 2, 2009	\$ 395,819	\$	\$	\$	\$	\$ (15,081)	\$380,738
Successor							
Balance at September 2, 2009 (Predecessor)	\$ 395,819	\$	\$	\$	\$	\$ (15,081)	\$380,738
Net income	2,488						2,488
Net effect of pushdown accounting	34,437					15,081	49,518
Balance at December 31, 2009	\$ 432,744	\$	\$	\$	\$	\$	\$432,744
Net income attributable to the period from January 1, 2010 through May 4, 2010	5,428						5,428
Extinguishment of related party note payable to PAA	16,375						16,375
Contribution of net assets to PAA Natural Gas Storage, L.P.	(454,547)	205,422	158,088	78,888	12,149		
Issuance of common units to public, net of offering and other costs		268,168					268,168
Modification of subordinated units			(22,903)	22,903			

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Equity compensation expense	369		1,446		1,815
Modification of LTIP awards	912				912
Net income attributable to the period from May 5, 2010 through December 31, 2010	16,971	6,851	537		24,359
Distributions to unitholders	(17,337)	(6,974)	(496)		(24,807)
Distribution equivalent right payments	(16)				(16)
Contribution from general partner			1		1
Net deferred loss on cash flow hedges				(1,589)	(1,589)
Balance at December 31, 2010	\$ 474,489	\$135,062	\$101,791	\$13,637	\$ (1,589)
					\$723,390

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

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PAA NATURAL GAS STORAGE, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

	Year Ended December 31, 2010	Successor September 3, 2009 through December 31, 2009 (See Note 1)	Predecessor January 1, 2009 through September 2, 2009 (See Note 1)	Year Ended December 31, 2008
Cash flows from operating activities				
Net income	\$ 29,787	\$ 2,488	\$ 15,518	\$ 19,586
Adjustments to reconcile to cash flow from operations				
Depreciation, depletion and amortization	14,119	3,578	8,054	6,245
Equity compensation expense	1,815			
Non-cash change in fair value of derivative instruments	(370)			(548)
Non-cash interest expense on borrowings from parent, net	5,081	4,262		
Change in assets and liabilities				
Accounts receivable and other assets	(5,264)	(480)	(2,166)	(5,097)
Accounts payable and accrued liabilities	(807)	5,417	1,197	1,632
Net cash provided by operating activities	44,361	15,265	22,603	21,818
Cash flows from investing activities				
Additions to property and equipment	(74,268)	(19,301)	(47,542)	(111,697)
Cash paid for base gas	(9,488)	(4,366)	(11,193)	(12,913)
Decrease (increase) in restricted cash and cash equivalents	(20,000)	14,000	(6)	5,090
Proceeds from sale of assets	176	11	180	630
Net cash provided by (used in) investing activities	(103,580)	(9,656)	(58,561)	(118,890)
Cash flows from financing activities				
Repayments on term loan agreement		(25,213)	(1,225)	(2,450)
Borrowings on revolving credit facility	322,200		59,400	65,000
Repayments of borrowings on revolving credit facility	(62,300)		(29,900)	
Borrowings from parent	24,000	2,400		
Repayment of borrowings from parent	(468,363)			
Net proceeds from issuance of common units	268,168			
Costs incurred in connection with financing arrangements	(2,441)		(4,639)	(206)

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Contribution from general partner	1			
Distributions paid to common limited partners	(24,311)			
Distributions paid to general partner	(496)			
Distribution equivalent right payments	(17)			
Contributions from members			8,500	74,500
Distributions to members			(8,500)	(14,500)
Net cash provided by (used in) financing activities	56,441	(22,813)	23,636	122,344
Net decrease in cash and cash equivalents	(2,778)	(17,204)	(12,322)	25,272
Cash and cash equivalents				
Beginning of period	3,124	20,328	32,650	7,378
End of period	\$ 346	\$ 3,124	\$ 20,328	\$ 32,650
Cash paid for interest, net of amounts capitalized	\$ 2,094	\$	\$ 2,298	\$ 5,197
Cash paid for income taxes	\$	\$	\$ 795	\$ 290
Non-cash items				
Change in non-cash asset purchases included in accounts payable	\$ (2,872)	\$ 1,008	\$ 1,534	\$ (6,582)
Non-cash interest capitalized on borrowings from parent	\$ 5,130	\$ 5,362	\$	\$

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

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Table of Contents**PAA NATURAL GAS STORAGE, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS****Note 1 Organization, Nature of Operations and Basis of Presentation*****Organization, Nature of Operation, Basis of Consolidation and Presentation***

PAA Natural Gas Storage, L.P. (the Partnership or PNG) is a Delaware limited partnership formed on January 15, 2010 to own the natural gas storage business of Plains All American Pipeline, L.P. (PAA). The Partnership is a fee-based, growth-oriented partnership engaged in the ownership, acquisition, development, operation and commercial management of natural gas storage facilities. As of December 31, 2010, we own and operate two natural gas storage facilities located in Louisiana and Michigan.

Our Pine Prairie facility is a recently constructed, high-deliverability salt cavern natural gas storage complex located in Evangeline Parish, Louisiana. As of December 31, 2010, Pine Prairie had a total working gas storage capacity of approximately 24 billion cubic feet (Bcf) in three caverns. 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, 2010, Bluewater had a total working gas storage capacity of approximately 26 Bcf in two depleted reservoirs.

As further discussed in Note 5, on May 5, 2010, the Partnership completed its initial public offering (IPO) pursuant to which PAA sold an approximate 23.0% limited partner interest in the Partnership to the public. Immediately prior to the closing of the IPO on May 5, 2010, PAA and certain of its consolidated subsidiaries contributed 100.0% of the equity interests in PAA Natural Gas Storage, LLC (PNGS), the predecessor of the Partnership, and its subsidiaries to the Partnership. For periods prior to our initial public offering, the accompanying consolidated financial statements of PNG reflect the predecessor financial statements of the Partnership. Prior to the IPO, the financial statements of the Partnership consisted of total assets of \$1,000 and the Partnership had not conducted any activity since its formation on January 15, 2010. The accompanying condensed consolidated financial statements, to the extent they relate to periods prior to the IPO, have been prepared from the separate financial records maintained by PNGS or its predecessor, as applicable, and may not necessarily be indicative of the actual results of operations that might have occurred if the Partnership had operated separately during those periods. As of December 31, 2010, PAA owned approximately 77.0% of the equity interests in the Partnership including our 2.0% general partner interest and limited partner interests consisting of 18,106,529 common units, 11,934,351 Series A subordinated units and 13,500,000 Series B subordinated units.

On September 3, 2009, PAA became the sole owner of PNGS by acquiring Vulcan Capital's 50.0% interest in PNGS (PAA Ownership Transaction) for an aggregate purchase price of \$215.0 million. Although PNGS continued as the same legal entity after the PAA Ownership Transaction, all of its assets and liabilities were adjusted to fair value at the time of the transaction in accordance with push-down accounting requirements. The remeasurement of PNGS's assets and liabilities to fair value resulted in changes in carrying value for certain of PNGS's assets and liabilities. The changes in carrying value are summarized as follows (in thousands):

PP&E, net	\$ 153,800
Base gas	(38,338)
Goodwill	(61,398)
Other long term assets	(4,546)
	\$ 49,518

As a result of the push-down accounting requirements applied in conjunction with the PAA Ownership Transaction, 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. Where applicable, 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 accompanying consolidated financial statements include the accounts of PNG and its subsidiaries or its predecessors (when applicable), all of which are wholly-owned. All significant intercompany transactions have been

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eliminated. Certain reclassifications have been made to the previous years to conform to the 2010 presentation. These reclassifications do not affect net income.

As used in this document, the terms we, us, our and similar terms refer to the Partnership and its subsidiaries, including its predecessors (when applicable), unless the context indicates otherwise.

Note 2 Summary of Significant Accounting Policies**Use of Estimates**

The preparation of financial statements in conformity with generally accepted accounting principles requires us to make estimates and assumptions that affect the reported amount of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. We make significant estimates with respect to: (i) mark-to-market estimates of derivative instruments, (ii) accruals and contingent liabilities, (iii) estimated fair value of assets and liabilities acquired and identification of associated goodwill and intangible assets, (iv) accruals related to incentive compensation, (v) valuation and recoverability of long-lived assets including property and equipment and goodwill and (vi) depreciation, depletion and amortization expense. Although we believe these estimates are reasonable, actual results could differ from these estimates.

Revenue Recognition

We provide various types of natural gas storage services to customers. Revenues from these activities are classified as firm storage services or hub services.

Firm storage services consist of:

- (i) *firm storage reservation fees* fixed monthly capacity reservation fees which are owed to us regardless of the actual storage capacity utilized by the customer. These fees are recognized in revenue ratably over the term of the contract regardless of the actual storage capacity utilized; this also includes seasonal park and loan services, pursuant to which a customer will pay fees for the firm right to store gas in (park), or borrow gas from (loan), our facilities on a seasonal basis; and
- (ii) *firm storage cycling fees and fuel-in-kind* fees for the use of injection and withdrawal services are based on the volume of natural gas nominated for injection and/or withdrawal; these fees are recognized in revenue in the period the volumes are nominated. We retain a small portion of the natural gas nominated for injection as compensation for our fuel use; the fuel-in-kind is reflected as revenue when received and in operating expense in the period the fuel is used in operations. Any excess fuel collected is carried as inventory at average cost.

Hub services consist of:

- (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) non-seasonal 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.

We may also retain a small portion of natural gas nominated for injection as compensation for our fuel use. These fees are recognized in revenue in the month that the services are provided.

Other revenue includes revenues from the sale of crude oil and 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 for our facilities. Such revenue is recognized at the time title to the product sold transfers to the purchaser or its designee. Other revenue also includes unrealized and realized gains and losses associated with certain commodity derivatives which we have entered into which have not been eligible for hedge accounting.

Table of Contents**Storage Related Costs**

Storage related costs consist of: (i) fees incurred to lease third party storage capacity and pipeline transportation capacity; and (ii) costs associated with certain loan services (see Base Gas). These costs are incurred to increase our operational flexibility and enhance the services we offer our customers.

Other Operating Costs and General and Administrative Expenses

Other operating costs consist of various field operating expenses, including power costs, telecommunications, payroll and benefit costs (including equity compensation expense) for field personnel, maintenance and integrity management costs, regulatory compliance, insurance and property taxes. General and administrative expenses consist primarily of payroll and benefit costs (including equity compensation expense), costs allocated to us from PAA, legal costs, acquisition related costs, contract and consultant costs and audit and tax fees.

Cash and Cash Equivalents and Restricted Cash

Cash, restricted cash and cash equivalents consist of all demand deposits and funds invested in highly liquid instruments with original maturities of three months or less. At December 31, 2010, cash equivalents are concentrated in two financial institutions and at times may exceed federally insured limits. We periodically assess the financial condition of the financial institutions and believe that our credit risk is minimal. As of December 31, 2010 and 2009, accounts payable included approximately \$0.4 million and \$1.0 million, respectively, of outstanding checks that were reclassified from cash and cash equivalents to accounts payable and accrued liabilities. As of December 31, 2010, restricted cash consists of a \$20 million deposit held in escrow in conjunction with the acquisition discussed in Note 14.

Accounts Receivable and Allowance for Doubtful Accounts

Our accounts receivable are from a broad mix of customers, including local gas distribution companies, electric utilities, pipelines, direct industrial users, electric power generators, marketers, producers, LNG importers and affiliates of such entities. We have a rigorous credit review process and closely monitor the potential credit risks associated with these counterparties in order to make a determination with respect to the amount, if any, of credit to be extended to any given customer and the form and amount of financial performance assurances we require. Such financial assurances are commonly provided to us in the form of standby letters of credit or parental guarantees.

We establish provisions for losses on accounts receivable if we determine that we will not collect all or part of an outstanding receivable balance. We regularly review collectability and establish or adjust our allowance as necessary using the specific identification method. As of December 31, 2010 and December 31, 2009, substantially all of our accounts receivable were current and we had no allowance for doubtful accounts. We have not had any material accounts receivable write-offs since our inception.

Goodwill and Other Intangible Assets

Our goodwill and other intangible assets balances at December 31, 2010 and December 31, 2009 consisted of the following (in thousands):

	December 31, 2010	December 31, 2009
Goodwill	\$ 24,966	\$ 24,549
Intangible assets	25,441	23,000
Goodwill and intangibles	50,407	47,549
Accumulated amortization	(2,861)	(575)
Goodwill and intangibles, net	\$ 47,546	\$ 46,974

We test goodwill at least annually and on an interim basis if a triggering event occurs to determine whether an impairment has occurred. Goodwill is tested for impairment at a level of reporting referred to as a reporting unit. A reporting unit is an operating segment or one level below an operating segment for which discrete financial

information is available and regularly reviewed by management. Our reporting units are our operating segments. Our operating segments are our Bluewater facility and our Pine Prairie facility (see Note 13). It is a two step process to test goodwill for impairment. In Step

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1, we compare the fair value of the reporting unit with the respective book values, including goodwill. When the fair value is greater than book value, then the reporting unit's goodwill is not considered impaired. If the book value is greater than fair value, then we proceed to Step 2. In Step 2, we compare the implied fair value of the reporting unit's goodwill with the book value. A goodwill impairment loss is recognized if the carrying amount exceeds its fair value. In conjunction with the PAA Ownership Transaction, we revalued all of our assets and liabilities to fair value, resulting in a new Successor goodwill balance of \$24.5 million at December 31, 2009. We test goodwill at least annually on June 30 of each year to determine if an impairment has occurred. There were no goodwill impairments during the 2010, 2009 and 2008 periods.

The table below reflects our changes in goodwill for the periods ended December 31, 2010 and December 31, 2009 (in thousands):

Predecessor

Balance at December 31, 2008	\$ 86,064
Balance at September 2, 2009	\$ 86,064

Successor

Elimination of predecessor goodwill	(86,064)
Goodwill pushed down from PAA Ownership Transaction	24,549
Change in goodwill	(61,515)
Balance at December 31, 2009	\$ 24,549
Push down accounting adjustment	417
Balance at December 31, 2010	\$ 24,966

During the year ended December 31, 2010, we recorded approximately \$0.4 million of adjustments to amounts originally pushed down to us in conjunction with the PAA Ownership Transactions. Such adjustments were related to changes in estimates of income tax related asset and liabilities associated with periods prior to the PAA Ownership Transaction.

We amortize finite lived intangible assets over our best estimate of their useful life and in the periods that we estimate that the economic benefits of the intangible assets are realized. An impairment loss is recognized for intangibles if the carrying amount of an intangible asset is not recoverable and its carrying amount exceeds its fair value. Intangible assets are tested for impairment when events or circumstances indicate that the carrying value may not be recoverable. The intangible costs are amortized on a straight-line basis. In conjunction with the PAA Ownership Transaction, we revalued all of our assets and liabilities to fair value. Our intangible assets consisted of the following (in thousands):

	Lives⁽¹⁾ (In Years)	December 31, 2010	December 31, 2009
Property tax abatement	13	\$ 23,000	\$ 23,000
Debt issue costs ⁽²⁾	3	2,441	0
Total intangible assets		25,441	23,000
Less: Accumulated amortization		(2,861)	(575)

Total intangible assets, net of amortization	\$	22,580	\$	22,425
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- (1) At the point of revaluing our assets to fair value, we also reassessed the estimated useful lives used for amortization purposes and revised them accordingly.
- (2) Costs incurred in connection with the issuance of the long-term debt and amendments to our credit facilities are capitalized and amortized using the straight-line method over the term of the related debt. In conjunction with the PAA Ownership Transaction, the remaining balances of amortized and unamortized debt issues costs were eliminated in conjunction with the repayment of the debt on September 2, 2009. We incurred approximately \$2.4 million of debt issuance costs in connection with our senior unsecured revolving credit facility (See Note 4). Such costs are being

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amortized over the term of the credit facility using the straight-line method of amortization. Amortization of debt issuance costs is reflected as a component of depreciation, depletion and amortization expenses in our accompanying condensed consolidated statements of operations.

Amortization expense related to our intangible assets was \$2.3 million, \$0.6 million, \$1.6 million and \$1.1 million for the periods ended December 31, 2010, December 31, 2009, September 2, 2009 and December 31, 2008, respectively. We estimate that our amortization expense related to our finite lived intangible assets for the next five years will be as follows (in thousands):

Calendar Year	Expense
2011	\$2,539
2012	2,524
2013	1,991
2014	1,725
2015	1,725

Asset Retirement Obligations

Financial Accounting Standards Board (FASB) guidance establishes accounting requirements for retirement obligations associated with tangible long-lived assets, including (1) the timing of the liability recognition, (2) initial measurement of the liability, (3) allocation of asset retirement cost to expense, (4) subsequent measurement of the liability and (5) financial statement disclosures. FASB guidance also requires that the cost for asset retirement should be capitalized as part of the cost of the related long-lived asset and subsequently allocated to expense using a systematic and rational method.

Some of our assets have contractual or regulatory obligations to perform remediation when the assets are abandoned. These assets, with regular maintenance, will continue to be in service for many years to come. It is not possible to predict when demands for our services will cease and we do not believe that such demand will cease for the foreseeable future. Accordingly, we believe the date when these assets will be abandoned is indeterminate. With no reasonably determinable abandonment date, we cannot reasonably estimate the fair value of the associated asset retirement obligation. We will record an asset retirement obligation in the period in which sufficient information becomes available for us to reasonably determine the settlement date.

Impairment of Long-Lived Assets

Long-lived assets with recorded values that are not expected to be recovered through future cash flows are written down to estimated fair value in accordance with FASB guidance over the accounting for the impairment or disposal of long-lived assets. Under this guidance, a long-lived asset is tested for impairment when events or circumstances indicate that its carrying value may not be recoverable. The carrying value of a long-lived asset is not recoverable if it exceeds the sum of the undiscounted cash flows expected to result from the use and eventual disposition of the asset. If the carrying value exceeds the sum of the undiscounted cash flows, an impairment loss equal to the amount by which the carrying value exceeds the fair value of the asset is recognized.

We periodically evaluate property and equipment for impairment when events or circumstances indicate that the carrying value of these assets may not be recoverable. The evaluation is highly dependent on the underlying assumptions of related cash flows. 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

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

There were no impairments in the 2010, 2009 and 2008 periods.

Property and Equipment

In accordance with our capitalization policy, costs associated with acquisitions and improvements that expand our existing capacity, including related interest costs, are capitalized. In addition, we capitalize cash expenditures made for the purpose of maintaining or replacing the operating capacity, service capability and/or functionality of our existing assets. Repair and maintenance expenditures incurred in order to maintain the day-to-day operation of our existing assets are charged to expense as incurred.

In conjunction with the development and expansion of our natural gas storage facilities, we capitalize direct costs associated with the development and construction projects. We also capitalize interest associated with projects that have not yet been placed into service. Capitalized interest was \$7.6 million for the year ended December 31, 2010, \$5.4 million and \$10.2 million for the periods September 3, 2009 through December 31, 2009 and January 1, 2009 through September 2, 2009, respectively, and \$19.0 million for the year ended December 31, 2008.

Property and equipment, net is stated at cost and consisted of the following (in thousands):

	Lives ⁽¹⁾ (In Years)	December 31, 2010	December 31, 2009
Natural gas storage facilities and equipment	50 to 70	\$ 742,526	\$ 539,870
Office property, equipment and other	3 to 5	48	48
Oil and gas properties	n/a	1,986	1,986
Land	n/a	8,288	8,288
Construction work in progress	n/a	139,797	266,075
		892,645	816,267
Less: Accumulated depreciation and depletion		(14,837)	(3,004)
Property and equipment, net		\$ 877,808	\$ 813,263

(1) At the point of revaluing our assets to fair value in conjunction with the PAA Ownership Transaction, we also reassessed the estimated useful lives used for depreciation purposes and revised them accordingly.

Depreciation and depletion expense related to our property and equipment for the twelve months ended December 31, 2010, the period from September 3, 2009 through December 31, 2009, the period from January 1, 2009 through September 2, 2009 and the twelve months ended December 31, 2008 was \$11.8 million, \$3.0 million, \$6.0 million and \$4.8 million, respectively.

Although our Bluewater facility includes certain oil and gas producing properties, the production of oil and gas is not our main line of business and thus, we view these assets as ancillary to our existing operations. The terms of our agreement with the former owners of Bluewater requires us to produce these crude oil proved reserves subject to certain conditions. We have capitalized our costs to acquire such properties and such costs are depreciated and depleted by the unit of production method.

The Pine Prairie facility is being managed, developed and constructed as one project. We will place assets into service in several phases and begin depreciation of these assets and an applicable portion of the other related assets when they are complete and ready for their intended use.

We calculate our depreciation using the straight-line method, based on estimated useful lives and salvage values of our assets. These estimates are based on various factors including condition, age (in the case of acquired assets), manufacturing specifications, technological advances and historical data concerning useful lives of similar assets. Uncertainties that impact

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these estimates include changes in laws and regulations relating to restoration and abandonment requirements, economic conditions, and supply and demand in the area. When assets are put into service, we make estimates with respect to useful lives and salvage values that we believe are reasonable. However, subsequent events could cause us to change our estimates, thus impacting the future calculation of depreciation and amortization.

At December 31, 2010 and 2009, the property and equipment balance includes approximately \$4.9 million and \$6.4 million, respectively, of accrued costs. Such amounts are reflected as a component of accounts payable and accrued liabilities in our consolidated balance sheets.

Base Gas

Base gas volumes at December 31, 2010 and 2009 consisted of approximately 11.2 Bcf and approximately 9.2 Bcf of natural gas in our storage facilities, respectively, which is necessary to operate the facilities. Approximately 7.0 Bcf was recorded at fair value as of September 2, 2009 due to the PAA Ownership Transaction with the remainder representing native natural gas within a depleted reservoir that is ascribed zero value due to uncertainty regarding our ability to ultimately recover such gas. Base gas volumes ascribed zero value were approximately 2.2 Bcf at December 31, 2010 and 2009, respectively. Purchases of base gas subsequent to the PAA Ownership Transaction are carried at historical cost. The level of necessary base gas fluctuates based on the utilization of the caverns and reservoirs. At times, dependent on market conditions and utilization of the facilities, base gas may be loaned to customers. We classify amounts outstanding under base gas loans as a component of base gas in the accompanying consolidated financial statements. This gas will continue to be utilized as base gas, a long-term asset, upon settlement of the loan. As of December 31, 2010, we had outstanding loan agreements totaling approximately 6.6 Bcf of natural gas, all of which are scheduled to be returned to us in the first quarter of 2011 in accordance with the terms of the agreements.

Gas Imbalances

We value gas imbalances due to or from interconnecting pipelines at market price as of the balance sheet date. Gas imbalances represent the difference between customer nominations and actual gas receipts from and gas deliveries to our interconnecting pipelines under various operational balancing agreements. As the settlements of imbalances are in-kind, changes in the balances do not have an impact on our earnings or cash flows.

Derivative Instruments and Hedging Activities

We identify the risks that underlie our core business activities and utilize risk management strategies to mitigate those risks when we determine that there is value in doing so. We use various derivative instruments to (i) manage our exposure to commodity price risk as well as to optimize our profits and (ii) manage our exposure to interest rate risk. We record all open derivative instruments on the balance sheet as either assets or liabilities measured at their fair value per the guidance issued by the FASB. This guidance requires that changes in the fair value of derivative instruments be recognized currently in earnings unless specific hedge accounting criteria are met, in which case, changes in fair value of cash flow hedges are deferred in AOCI and reclassified into earnings when the underlying transaction affects earnings. Accordingly, changes in fair value are included in current period earnings for (i) derivatives that do not qualify for hedge accounting and (ii) the portion of cash flow hedges that are not highly effective in offsetting changes in cash flows of hedged items. See Note 6 for further discussion.

Fair Value

Among other things, ASC 820 *Fair Value Measurements and Disclosures* requires enhanced disclosures about assets and liabilities carried at fair value. As defined in ASC 820, fair value is the price that would be received from selling an asset, or paid to transfer a liability, in an orderly transaction between market participants at the measurement date. ASC 820 establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3).

The determination of the fair values incorporates various factors required under ASC 820. These factors include not only the credit standing of the counterparties involved and the impact of credit enhancements, but also the impact of nonperformance risk on our liabilities. Our interest rate swap agreements, which were outstanding during the predecessor periods and were terminated in conjunction with the PAA Ownership Transaction, were designated as Level 3 within the fair

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value hierarchy as the broker or dealer price quotations used to measure the fair value and the pricing services used to corroborate the quotations are indicative quotations rather than quotations whereby the broker or dealer is ready and willing to transact. However, the fair value of these Level 3 derivatives are not based on significant management assumptions or subjective inputs.

As of December 31, 2010 and December 31, 2009, all of our derivatives consisted of exchange-traded instruments within active markets. We therefore consider all of our derivatives as of December 31, 2010 and December 31, 2009 to be Level 1 fair value measurements.

Income and Other Taxes

No provision for U.S. federal income taxes related to our operations is included in our consolidated financial statements as we are treated as a partnership not subject to federal income tax and the tax effect of our activities accrues to our members. Income tax expense shown on our consolidated statement of operations for applicable predecessor periods is related to tax obligations of our predecessor. As a result of PAA obtaining control over us in conjunction with the PAA Ownership Transaction, we report income taxes on a consolidated basis with PAA and are allocated our share of applicable tax obligations. Such amounts were not material for any periods subsequent to the PAA Ownership Transaction.

At December 31, 2010 and 2009, we had an income tax refund receivable of approximately \$0.8 million and \$1.1 million, respectively, included in other current assets on our consolidated balance sheet.

At December 31, 2010 and 2009, we have no material assets, liabilities or accrued interest associated with uncertain tax positions.

Environmental Matters

We record environmental liabilities when environmental assessments and/or remediation efforts are probable and we can reasonably estimate the costs. Generally, our recording of these accruals coincides with the completion of a feasibility study or our commitment to a formal plan of action. Management is not aware of any association with any known material environmental liabilities as of December 31, 2010.

Recent Accounting Pronouncements

In January 2010, the FASB issued guidance to enhance disclosures related to the existing fair value hierarchy disclosure requirements. A fair value measurement is designated as level 1, 2 or 3 within the hierarchy based on the nature of the inputs used in the valuation process. Level 1 measurements generally reflect quoted market prices in active markets for identical assets or liabilities, level 2 measurements generally reflect the use of significant observable inputs and level 3 measurements typically utilize significant unobservable inputs. This new guidance requires additional disclosures regarding transfers into and out of level 1 and level 2 measurements and requires a gross presentation of activities within the level 3 roll forward. This guidance was effective for the first interim or annual reporting period beginning after December 15, 2009, except for the gross presentation of the level 3 roll forward, which is required for annual reporting periods beginning after December 15, 2010 and for interim reporting periods within those years. We adopted the guidance relating to level 1 and level 2 measurements as of January 1, 2010, and we adopted the guidance relating to level 3 measurements on January 1, 2011. Our adoption did not have any material impact on our financial position, results of operations or cash flows.

Net Income Per Limited Partner Unit

Basic and diluted net income per unit is determined by dividing each class of limited partners' interest in net income by the weighted average number of limited partner units for such class outstanding during the period. Pursuant to FASB guidance, the limited partners' interest in net income is calculated by first reducing net income by the distribution pertaining to the current period's net income, which is to be paid in the subsequent quarter (including the incentive distribution right in excess of the 2.0% general partner interest). Then, the remaining undistributed earnings or excess distributions over earnings, if any, are allocated to the general partner and limited partner interests in accordance with the contractual terms of the partnership agreement. Diluted earnings per limited partner unit, where applicable, reflects the potential dilution that could occur if securities or other agreements to issue additional units of a limited partner class, such as phantom unit awards, were exercised, settled or converted into such units.

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The following table sets forth the computation of basic and diluted earnings per limited partner unit for the period from May 5, 2010 (the closing of our initial public offering) through December 31, 2010 (amounts in thousands, except per unit data):

	May 5, 2010 to December 31, 2010
Net income	\$ 24,359
Less: General partner's incentive distribution paid ⁽¹⁾	51
Less: General partner 2.0% ownership	486
Net income available to limited partners	\$ 23,822
Numerator for basic and diluted earnings per limited partner unit:	
Allocation of net income amongst limited partner interests:	
Net income allocable to common units	\$ 16,971
Net income allocable to Series A subordinated units	6,851
Net income allocable to Series B subordinated units ⁽²⁾	
Net income available to limited partners	\$ 23,822
Denominator:	
Basic and diluted weighted average number of limited partner units outstanding: ⁽²⁾⁽³⁾⁽⁴⁾	
Common units	31,586
Series A subordinated units	12,789
Series B subordinated units	12,645
Basic and diluted net income per limited partner unit: ⁽²⁾⁽³⁾⁽⁴⁾	
Common units	\$ 0.54
Series A subordinated units	\$ 0.54
Series B subordinated units	\$

- (1) Based on the amount of the distribution declared per common and Series A subordinated limited partner unit related to earnings for the applicable periods, our general partner was not entitled to receive any incentive distributions prior to the fourth quarter of 2010.
- (2) As of December 31, 2010, our Series B subordinated units were not entitled to participate in our earnings, losses or distributions in accordance with the terms of our partnership agreement as necessary performance conditions have not been satisfied. As a result, no earnings were allocated to the Series B subordinated units in our determination of basic and diluted net income per limited partner unit.
- (3) Substantially all of our LTIP awards (described in Note 10), which are equity classified awards, contain provisions whereby vesting occurs only upon the satisfaction of a performance condition. None of the performance conditions on such awards had been satisfied as of December 31, 2010. As such, our outstanding LTIP awards as of December 31, 2010 did not have a material impact in our determination of diluted net income per limited partner unit.
- (4) The conversion of (i) our Series A subordinated units to common units and (ii) our Series B subordinated units to Series A subordinated units or common units is subject to certain performance conditions. None of these performance conditions had been satisfied as of December 31, 2010 therefore, there is no dilutive impact of such

units in our determination of diluted net income per limited partner unit.

Note 3 Acquisitions and Dispositions

During 2010 and 2009 we sold various property and equipment for proceeds totaling approximately \$0.2 million. Losses recognized related to these dispositions were immaterial.

Note 4 Debt

In April 2010, subject to consummation of our initial public offering, we entered into a three-year, \$400.0 million senior unsecured revolving credit facility that matures in May 2013. This credit facility, which bears interest based on LIBOR plus an applicable margin (approximately 3.4% in the aggregate including commitment fee as of December 31, 2010)

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determined based on funded debt-to-EBITDA levels (as defined in the credit agreement), may be expanded to \$600.0 million, subject to additional lender commitments and with approval of the administrative agent for the credit facility.

This credit facility restricts, among other things, the Partnership's ability to 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. In addition, the credit facility contains restrictive covenants, including those that restrict our ability to incur additional indebtedness, engage in certain transactions with affiliates, grant (or permit to exist) liens or enter into certain restricted contracts, 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. Also, the credit facility contains certain financial covenants which, among other things, requires us to maintain a debt-to-EBITDA coverage ratio that will not be greater than 4.75 to 1.00 on outstanding debt (5.50 to 1.00 on all outstanding debt during an acquisition period) and also requires that we maintain an EBITDA-to-interest coverage ratio that will not be less than 3.00 to 1.00, as such terms are defined in the credit agreement. As of December 31, 2010, we were in compliance with the covenants contained in our credit agreement.

At December 31, 2010, we estimate that the carrying value of outstanding borrowings under our credit facility approximates fair value as interest rates reflect current market rates.

Our credit facility includes the ability to issue letters of credit. As of December 31, 2010, we had no outstanding letters of credit.

As of December 31, 2009, approximately \$450.5 million was outstanding on a related party note payable to PAA, which was entered into in conjunction with the PAA Ownership Transaction. The note accrued interest and was payable in kind, at a rate of 6.5%. As discussed in Note 5, net proceeds of our initial public offering, along with borrowings under the new credit facility, were used to repay approximately \$468.4 million of the related party note, which included additional borrowings and interest accrued through May 5, 2010. The remaining balance of approximately \$16.4 million was extinguished and treated as a capital contribution by PAA as part of PAA's initial investment in the Partnership.

Note 5 Partners' Capital and Distributions***Initial Public Offering***

As discussed in Note 1, immediately prior to the closing of our initial public offering on May 5, 2010, PAA and its subsidiaries contributed 98.0% of the equity interests in PNGS to the Partnership in exchange for certain limited partner interests. In addition, PNGS GP LLC, the general partner of the Partnership and a subsidiary of PAA, contributed 2.0% of the equity interests in PNGS to the Partnership in exchange for a 2.0% general partner interest in the Partnership as well as all of our incentive distribution rights, which entitle our general partner to increasing percentages of the cash we distribute in excess of \$0.3375 per quarter.

On May 5, 2010, the Partnership issued approximately 13.5 million common units to the public, which included approximately 1.8 million common units issued pursuant to the full exercise of the underwriters' over-allotment option, through an underwritten initial public offering representing an approximate 23.0% limited partner interest in us. Upon closing of the initial public offering and after giving effect to the exercise of the underwriters' over-allotment option, PAA and its subsidiaries retained an approximate 77.0% equity interest in the Partnership, consisting of approximately 18.1 million common units, approximately 13.9 million Series A subordinated units, 11.5 million Series B subordinated units and a 2.0% general partner interest in us. Total proceeds of the initial public offering were approximately \$289.8 million. After deducting underwriting discounts and commissions and direct offering expenses, net proceeds of the offering were approximately \$268.2 million. Net proceeds of the offering, along with \$200.0 million of borrowings under the Partnership's new \$400.0 million senior unsecured revolving credit facility, were used to repay intercompany indebtedness owed to PAA. The remaining balance of the intercompany indebtedness owed to PAA of approximately \$16.4 million was extinguished and treated as a capital contribution and part of PAA's initial investment in the Partnership.

Outstanding Units

From the closing of our initial public offering on May 5, 2010 through December 31, 2010, changes in our issued and outstanding common, Series A subordinated and Series B subordinated units were as follows:

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	Subordinated			Total
	Common	Series A	Series B	
Balance, May 5, 2010				
Initial public offering	31,584,529	13,934,351	11,500,000	57,018,880
Modification of subordinated units		(2,000,000)	2,000,000	
Vesting of LTIP awards	1,876			1,876
Balance, December 31, 2010	31,586,405	11,934,351	13,500,000	57,020,756

Modification of subordinated units

In August 2010, our general partner amended and restated the Amended and Restated Agreement of Limited Partnership of the Partnership (the Second Amended and Restated Agreement) to increase our distribution coverage and growth profile of our common and Series A subordinated units and improve our posture with respect to potential acquisitions. The Second Amended and Restated Agreement reduced the number of Series A subordinated units held by PAA by 2.0 million units and increased the number of Series B subordinated units held by PAA by an equivalent amount. The Second Amended and Restated Agreement also established two additional tranches of Series B subordinated units. We accounted for this transaction as an exchange between entities under common control and accordingly, we reclassified approximately \$22.9 million, the book value of 2.0 million Series A subordinated units at the time of the transaction, from the Series A subordinated unit limited partner capital account to the Series B subordinated unit limited partner capital account in our accompanying condensed consolidated statement of changes in partners' capital and members' capital.

Series A subordinated units

All of our Series A subordinated units are owned by PAA. The principal difference between our common units and Series A subordinated units is that in any quarter during the subordination period, holders of the Series A subordinated units are not entitled to receive any distribution until the common units have received the minimum quarterly distribution plus any arrearages in the payment of the minimum quarterly distribution from prior quarters. Series A subordinated units will not accrue arrearages.

At any time on or after June 30, 2013, the subordination period for the Series A subordinated units will end on the first business day following the quarter in respect of which we have, for each of three consecutive, non-overlapping four quarter periods (i) generated from distributable cash flow at least \$1.35 (the minimum quarterly distribution on an annualized basis) on the weighted average number of outstanding common units and Series A subordinated units on a fully diluted basis, plus the corresponding distribution on our general partner's 2.0% interest and (ii) paid from available cash at least \$1.35 on all outstanding common units and Series A subordinated units, plus the corresponding distribution on our general partner's 2.0% interest. Additionally, at any time on or after June 30, 2011, if we have, for a period of four consecutive quarters (i) generated from distributable cash flow at least \$0.5063 per quarter (150.0% of the minimum quarterly distribution, which is approximately \$2.03 on an annualized basis) on the weighted average number of outstanding common units and Series A subordinated units on a fully diluted basis, plus the corresponding distributions on our general partner's 2.0% interest and the related distributions on the incentive distribution rights and (ii) paid from available cash at least \$0.5063 per quarter (150.0% of the minimum quarterly distribution, which is approximately \$2.03 on an annualized basis) on all outstanding common units and Series A subordinated units, plus the corresponding distribution on our general partner's 2.0% interest and the related distributions on the incentive distribution rights, the subordination period will end.

In addition, the subordination period will end upon the removal of our general partner other than for cause, if the units held by our general partner and its affiliates are not voted in favor of such removal.

When the subordination period ends, all Series A subordinated units will convert into common units on a one-for-one basis, and all common units thereafter will no longer be entitled to arrearages.

Series B subordinated units

All of our Series B subordinated units are owned by PAA. The Series B subordinated units will not be entitled to participate in our quarterly distributions until they convert into Series A subordinated units or common units.

The Series B subordinated units will convert into Series A subordinated units upon satisfaction of the following operational and financial conditions:

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2,600,000 Series B subordinated units will convert into Series A subordinated units on a one-for-one basis if (a) the aggregate amount of working gas storage capacity at Pine Prairie that has been placed into service totals at least 29.6 Bcf, (b) we generate distributable cash flow for two consecutive quarters sufficient to pay a quarterly distribution of at least \$0.36 per unit (representing an annualized distribution of \$1.44 per unit) on the weighted average number of outstanding common units and Series A subordinated units and all of such Series B subordinated units and (c) we make a quarterly distribution of available cash of at least \$0.36 per quarter for two consecutive quarters on all outstanding common units and Series A subordinated units and the corresponding distributions on our general partner's 2.0% interest and the related distributions on the incentive distribution rights;

2,833,333 Series B subordinated units will convert into Series A subordinated units on a one-for-one basis if (a) the aggregate amount of working gas storage capacity at Pine Prairie that has been placed into service totals at least 35.6 Bcf, (b) we generate distributable cash flow for two consecutive quarters sufficient to pay a quarterly distribution of at least \$0.3825 per unit (representing an annualized distribution of \$1.53 per unit) on the weighted average number of outstanding common units and Series A subordinated units and all of such Series B subordinated units and, if any, the Series B subordinated units described in the prior bullet, and (c) we make a quarterly distribution of available cash of at least \$0.3825 per quarter for two consecutive quarters on all outstanding common units and Series A subordinated units and the corresponding distributions on our general partner's 2.0% interest and the related distributions on the incentive distribution rights;

2,066,667 Series B subordinated units will convert into Series A subordinated units on a one-for-one basis if (a) the aggregate amount of working gas storage capacity at Pine Prairie that has been placed into service totals at least 41.6 Bcf, (b) we generate distributable cash flow for two consecutive quarters sufficient to pay a quarterly distribution of at least \$0.4075 per unit (representing an annualized distribution of \$1.63 per unit) on the weighted average number of outstanding common units and Series A subordinated units and all of such Series B subordinated units and, if any, the Series B subordinated units described in the prior two bullets, and (c) we make a quarterly distribution of available cash of at least \$0.4075 per quarter for two consecutive quarters on all outstanding common units and Series A subordinated units and the corresponding distributions on our general partner's 2.0% interest and the related distributions on the incentive distribution rights;

3,000,000 Series B subordinated units will convert into Series A subordinated units on a one-for-one basis if (a) the aggregate amount of working gas storage capacity at Pine Prairie that has been placed into service totals at least 48 Bcf, (b) we generate distributable cash flow for two consecutive quarters sufficient to pay a quarterly distribution of at least \$0.4275 per unit (representing an annualized distribution of \$1.71 per unit) on the weighted average number of outstanding common units and Series A subordinated units and all of such Series B subordinated units and, if any, the Series B subordinated units described in the prior three bullets, and (c) we make a quarterly distribution of available cash of at least \$0.4275 per quarter for two consecutive quarters on all outstanding common units and Series A subordinated units and the corresponding distributions on our general partner's 2.0% interest and the related distributions on the incentive distribution rights; and

3,000,000 Series B subordinated units will convert into Series A subordinated units on a one-for-one basis if (a) the aggregate amount of working gas storage capacity at Pine Prairie that has been placed into service totals at least 48 Bcf, (b) we generate distributable cash flow for two consecutive quarters sufficient to pay a quarterly distribution of at least \$0.45 per unit (representing an annualized distribution of \$1.80 per unit) on the weighted average number of outstanding common units and Series A subordinated units and all of such Series B subordinated units and, if any, the Series B subordinated units described in the prior four bullets, and (c) we make a quarterly distribution of available cash of at least \$0.45 per quarter for two consecutive quarters on all outstanding common units and Series A subordinated units and the corresponding distributions on our general partner's 2.0% interest and the related distributions on the incentive distribution rights.

Before giving effect to the Second Amended and Restated Agreement, there were 4,600,000, 3,833,333 and 3,066,667 Series B subordinated units included in first, second and third tranches of Series B subordinated units, respectively.

Our general partner will determine whether the in-service operational requirements set forth above have been satisfied. To the extent that the operational tests described above are satisfied prior to or during the two-quarter period applicable to the financial tests described above, the holder of the Series B subordinated units subject to conversion will be entitled to receive the quarterly distribution payable with respect to the second quarter of such two-quarter period. In all other circumstances, where the operational tests are satisfied following the two-quarter period applicable to the financial tests, the holder of the

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Series B subordinated units subject to conversion will be entitled to receive any distribution payable following the satisfaction of such operational tests.

Any Series B subordinated units that remain outstanding as of December 31, 2018 will automatically be cancelled.

Following conversion of any Series B subordinated units into Series A subordinated units, such converted Series B subordinated units will further convert into common units (together with any other outstanding Series A subordinated units) to the extent that the tests for conversion of the Series A subordinated units are satisfied. In determining whether such conversion tests have been satisfied, the Series B subordinated units that have converted into Series A subordinated units will be treated as Series A subordinated units from and after the date of their conversion into Series A subordinated units.

If at the time the above operational and financial tests are satisfied, the subordination period has already ended and all outstanding Series A subordinated units have converted into common units, the Series B subordinated units will instead convert directly into common units on a one-for-one basis and participate in the quarterly distribution payable to common units.

Distributions

Our partnership agreement requires that, within 45 days subsequent to the end of each quarter, we will distribute 100% of our available cash, as defined in our partnership agreement, to unitholders of record on the applicable record date. Available cash is generally defined as all cash and cash equivalents on hand at the end of the quarter less reserves established by the managing member for future requirements.

Our partnership agreement requires that 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.

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%
	above \$0.3375 up to		
First target distribution	\$0.37125	85.0%	15.0%
	above \$0.37125 up to		
Second target distribution	\$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.

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

Date Declared	Date Paid or To Be Paid	Distributions Paid				Total	Distributions per limited partner unit
		Common	Subordinated	General Partner	Series A		
January 12, 2011	February 14, 2011 ⁽¹⁾	\$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 4, 2011, for the period October 1, 2010 through December 31, 2010.

⁽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.

Note 6 Derivatives and Hedging Instruments

From time to time, we may utilize derivative instruments to manage our exposure to interest rates, purchases and sales of natural gas and to economically hedge the intrinsic value of our natural gas storage facilities. Our policy is to formally document all relationships between hedging instruments and hedged items, as well as our risk management objectives and strategy for undertaking the hedge. This process includes specific identification of the hedging instrument and the hedged transaction, the nature of the risk being hedged and how the hedging instrument's effectiveness will be assessed. Both at the inception of the hedge and on an ongoing basis, we assess whether the derivatives that are used in hedging transactions are highly effective in offsetting changes in cash flows of hedged items. FASB guidance requires that changes in the fair value of derivative instruments be recognized currently in earnings unless specific hedge accounting criteria are met, in which case, the effective portion of changes in the fair value of cash flow hedges are deferred in accumulated other comprehensive income (AOCI) and reclassified into earnings when the underlying transaction affects earnings.

Commodity Price Risk Hedging

We use derivative financial instruments to hedge the following commodity risks inherent in our business:

Anticipated Purchases and Sales of Natural Gas Our gas storage facilities require minimum levels of base gas to operate. For our natural gas storage facilities that are under construction, we anticipate purchasing base gas in future periods as construction is completed. We use derivatives to hedge such anticipated purchases of natural gas. As of December 31, 2010, we have a long futures position of approximately 1 Bcf consisting of NYMEX futures and a long call option position of approximately 0.7 Bcf. Such positions were entered into during the first quarter of 2010. Additionally, we use derivatives to hedge anticipated purchases and sales of natural gas for commercial or operational purposes. As of December 31, 2010, all of our outstanding derivatives entered into for purposes of hedging anticipated purchases and sales of natural gas have been designated as cash flow hedges.

Interest Rate Risk Hedging

Prior to the PAA Ownership Transaction, we had previously entered into a series of interest rate swap agreements that were designated as cash flow hedges. These interest rate swaps were utilized to mitigate exposure to cash flow variability associated with variable rate interest payments on certain debt obligations. In conjunction with the PAA Ownership Transaction, all of the associated debt obligations were settled and all of these interest rate swap agreements were terminated. PAA paid approximately \$17.6 million to settle these interest rate swap agreements, which included approximately \$2.1 million associated with the net settlement due through the termination date. Such amount paid by PAA was included in the initial principal amount of our related party note payable to PAA as discussed in Note 4. Subsequent to the PAA Ownership Transaction, we have not entered into any additional interest rate swap agreements.

Summary of Financial Statement Impact

Derivatives that qualify for hedge accounting are designated as cash flow hedges. Changes in fair value for the effective portion of the hedges are deferred to AOCI and recognized in earnings in the periods during which the underlying hedged transaction impacts earnings. Derivatives that do not qualify for hedge accounting and the ineffective portion of cash

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flow hedges are recognized in earnings each period. Cash settlements associated with our derivative activities are reflected as operating cash flows in our consolidated statements of cash flows.

In December 2009, we entered into a natural gas storage related futures position. This derivative instrument was not eligible for hedge accounting. We settled this derivative for a realized loss of approximately \$0.8 million in 2010. We recognized lossess of approximately \$0.4 million and \$0.4 million in 2010 and 2009, respectively, which are reflected as components of other revenues during the respective periods.

During the year ended December 31, 2008, we entered into and settled a natural gas storage related futures position. This derivative instrument was not eligible for hedge accounting. Upon settlement of this transaction, we recognized a gain of approximately \$1.1 million which is reflected as a component of other revenues during the year ended December 31, 2008.

Our earnings were not impacted by derivative activities in cash flow hedging relationships during the period from September 3, 2009 to December 31, 2009. A summary of the impact of our derivative activities in cash flow hedging relationships recognized in earnings for the year ended December 31, 2008, the period from January 1, 2009 through September 2, 2009 and the year ended December 31, 2010 is as follows (in thousands):

Predecessor

		Year Ended December 31, 2008		
		Amount of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion) (1)	Amount of Gain/(Loss) Recognized in Income on Derivatives (Ineffective Portion) (2)	Total
Location of Gain/(Loss)				
Interest Rate Derivatives	Interest expense	\$(2,081)	\$	\$(2,081)

		January 1, 2009 through September 2, 2009		
		Amount of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion) (1)	Amount of Gain/(Loss) Recognized in Income on Derivatives (Ineffective Portion) (2)	Total
Location of Gain/(Loss)				
Interest Rate Derivatives	Interest expense	\$(6,613)	\$	\$(6,613)
	Gain on interest rate swaps		336	336
Total		\$(6,613)	\$ 336	\$(6,277)

Successor

		Year Ended December 31, 2010		
		Amount of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion) (1)	Amount of Gain/(Loss) Recognized in Income on Derivatives (Ineffective Portion) (2)	Total
Location of Gain/(Loss)				
Commodity Derivatives	Other revenues	\$ 816	\$	\$ 816

(1) Amounts represent derivative gains and losses that were reclassified from AOCI to earnings during the period to coincide with the earnings impact of the respective hedged transaction.

(2) Amounts represent the ineffective portion of the fair value of our cash flow hedges that were recognized in earnings during the period.

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The following table summarizes the derivative assets and liabilities on our consolidated balance sheet on a gross basis as of December 31, 2010 (in thousands):

	Asset Derivatives Balance Sheet		Liability Derivatives Balance Sheet	
	Location	Fair Value	Location	Fair Value
Commodity derivatives designated as hedging instruments	Other current assets	\$ 43	Other current assets	\$ (4)

The following table summarizes the derivative assets and liabilities on our consolidated balance sheet on a gross basis as of December 31, 2009 (in thousands):

	Asset Derivatives Balance Sheet		Liability Derivatives Balance Sheet	
	Location	Fair Value	Location	Fair Value
Commodity derivatives not designated as hedging instruments	Accounts payable and Accrued liabilities	\$ 37	Accounts payable and Accrued liabilities	\$(407)

As of December 31, 2010, there was a net loss of approximately \$1.6 million deferred in AOCI (no amounts were deferred in AOCI as of December 31, 2009). Amounts included in AOCI include amounts associated with terminated hedging instruments for which the underlying anticipated hedge transactions are still probable of occurring. The deferred loss in AOCI is expected to be reclassified to future earnings contemporaneously with the earnings recognition of the underlying hedged transactions. The underlying hedged transactions are for anticipated base gas purchases. As we account for base gas as a long-term asset, which is not subject to depreciation, amounts related to base gas will not be reclassified to future earnings until such gas is sold or in the event an impairment charge is recognized in the future. We do not expect to reclassify any of the \$1.6 million deferred loss as of December 31, 2010 into earnings during the next twelve months. Amounts deferred are based on market prices as of December 31, 2010, thus actual amounts to be reclassified will differ and could vary materially as a result of changes in market conditions. During 2010 and 2009, no amounts were reclassified from AOCI to earnings as a result of anticipated hedge transactions that were no longer considered to be probable of occurring.

Our accounting policy is to offset fair value amounts associated with derivatives executed with the same counterparty when a master netting agreement exists. Accordingly, we also offset derivative assets and liabilities with amounts associated with cash margin. Our exchange-traded derivatives are transacted through a brokerage account and are subject to margin requirements as established by the respective exchange. On a daily basis, our account equity (consisting of the sum of our cash balance and the fair value of our open derivatives) is compared to our initial margin requirement resulting in the payment or return of variation margin. As of December 31, 2010, we had a net broker receivable of approximately \$397 thousand (consisting of initial margin of \$301 thousand increased by \$96 thousand of variation margin posted by us). As of December 31, 2009, we did not have an obligation to pay or a right to receive cash collateral associated with our derivatives. At December 31, 2010 and December 31, 2009, none of our outstanding derivatives contained credit-risk related contingent features that would result in a material adverse impact upon a change in our credit ratings.

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The following table provides a reconciliation of changes in fair value of the beginning and ending balances for our interest rate swap agreements which were classified as Level 3 measurements in the fair value hierarchy (in thousands of dollars) since our adoption of the applicable provisions of ASC 820 on January 1, 2008:

	Predecessor
Beginning liability balance, January 1, 2008	\$ (7,265)
Unrealized gains and (losses)	
Included in earnings	548
Included in other comprehensive income ⁽¹⁾	(14,224)
Settlements ⁽²⁾	3,150
Beginning liability balance, January 1, 2009	\$ (17,791)
Unrealized gains and (losses)	
Included in earnings	336
Included in other comprehensive income ⁽¹⁾	(4,628)
Settlements ⁽²⁾	6,618
Ending liability balance, September 2, 2009	\$ (15,465)

(1) Reflects changes in accumulated other comprehensive income due to changes in fair value.

(2) Reflects amounts reclassified out of accumulated other comprehensive income to interest expense concurrent with the interest expense accruals associated with the underlying hedged debt.

Note 7 Comprehensive Income

Comprehensive income includes net income and all other non-owner changes in equity. Components of comprehensive income (loss) are presented below (in thousands):

	Successor		Predecessor	
	Year Ended December 31, 2010	September 3, 2009 through December 31, 2009	January 1, 2009 through September 2, 2009	Year Ended December 31, 2008
Net income	\$ 29,787	\$ 2,488	\$ 15,518	\$ 19,586
Net derivative gain/(loss) on cash flow hedges	(1,589)		1,990	(11,074)
Total comprehensive income	\$ 28,198	\$ 2,488	\$ 17,508	\$ 8,512

Note 8 Major Customers and Concentration of Credit Risk

During the year ended December 31, 2010, Iberdrola Renewables, Inc., Guardian Pipeline, LLC and Anadarko Energy Services accounted for approximately 13%, 9% and 8% of our storage revenues, respectively. During the period from September 3, 2009 to December 31, 2009, Anadarko Energy Services, Iberdrola Renewables, Inc. and Guardian Pipeline, LLC accounted for approximately 10%, 16% and 12% of our storage revenues, respectively. During the period from January 1, 2009 to September 2, 2009, Iberdrola Renewables, Inc. and Guardian Pipeline, LLC accounted for approximately 17% and 13% of our storage revenues, respectively. During the year ended December 31, 2008, ONEOK Energy Services Company LP, Iberdrola Renewables, Inc. and Guardian Pipeline, LLC

accounted for approximately 10%, 19% and 11% of our storage revenues, respectively. This concentration in the volume of business transacted with a limited number of customers subjects us to risk.

Financial instruments that subject us to concentrations of credit risk consist principally of trade receivables. Our accounts receivable are primarily from customers that operate in the natural gas industry. This industry concentration has the potential to impact our overall exposure to credit risk in that the customers may be similarly affected by changes in economic, industry or other conditions, which subjects us to credit risk. We review credit exposure and financial information of our customers and generally require letters of credit for receivables from customers that are not considered creditworthy, unless the credit risk can otherwise be reduced.

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Table of Contents**Note 9 Related Party Transactions**

We do not directly employ any persons to manage or operate our business. These functions are provided by employees of Plains All American GP LLC (GP LLC), the general partner of Plains AAP, L.P. which is the sole member of PAA GP LLC, PAA's general partner. References to PAA, unless the context otherwise requires, include GP LLC. We reimburse PAA for all direct and indirect expenses it incurs or payments it makes on our behalf and all other expenses allocable to us or otherwise incurred by PAA in connection with the operation of our business. These expenses are recorded in general and administrative expenses and other operating costs on our income statement and include salary, bonus, incentive compensation and other amounts paid to persons who perform services for us or on our behalf. We record these costs on the accrual basis in the period in which PAA's general partner incurs them. Our agreement with PAA provides that PAA will determine the expenses allocable to us in any reasonable manner determined by PAA in its sole discretion. The amount of the allocation increased after the PAA Ownership Transaction, as prior to September 2, 2009, the joint venture agreement with Vulcan Capital did not permit PAA to charge us for executive officer expenses and subsequent to the PAA Ownership Transaction PAA devoted a greater proportion of their resources to our operations. Instead, such items were compensated under a contingent management fee arrangement that was subject to achievement of performance benchmarks not considered probable. Such contingent management fee was addressed by the negotiation with Vulcan Capital and reflected in the total valuation. Total costs reimbursed by us to PAA for the periods ended December 31, 2010, December 31, 2009 and September 2, 2009, were approximately \$19.5 million, \$3.6 million and \$7.9 million, respectively. Of these amounts \$3.5 million, \$1.1 million, and \$1.0 million, respectively, were allocated personnel costs for shared services and the remainder consisted of direct costs that PAA paid on our behalf. PAA, in conjunction with input from our general partner, estimates the percentage of time that each shared service department spends on items related to our operations and allocates this percentage of their personnel costs to us. Due to our general partner's close involvement in this process, we believe that the method used is reasonable. As of December 31, 2010 and December 31, 2009, we had a liability to PAA of approximately \$0.6 million and \$1.8 million, respectively, included in accounts payable and accrued liabilities on the consolidated balance sheet.

Omnibus Agreement

In conjunction with our initial public offering in May 2010, we entered into an omnibus agreement with PAA and certain of its affiliates, pursuant to which we agreed upon certain aspects of our relationship with them, including, among other things (1) the provision by PAA's general partner to us of certain general and administrative services and our agreement to reimburse PAA's general partner for such services, (2) the provision by PAA's general partner of such personnel as may be necessary to operate and manage our business, and our agreement to reimburse PAA's general partner for the expenses associated with such personnel, (3) certain indemnification obligations, and (4) our use of the name PAA and related marks. Under this agreement, PAA indemnifies us against certain environmental liabilities, tax matters, and title or permitting defects generally for a period of three years after the closing of our initial public offering. The environmental indemnifications are subject to a cap of \$15.0 million and require us to pay the first \$250 thousand of costs incurred. In addition, we have indemnified PAA against any losses, costs or damages incurred by PAA or its general partner that are attributable to the ownership and operation of our assets following the close of the initial public offering.

Tax Sharing Agreement

In conjunction with our initial public offering in May 2010, we entered into a tax sharing agreement with PAA, pursuant to which we and PAA agreed on the method of allocation among us and our subsidiaries, on the one hand, and PAA and its subsidiaries (other than us and our subsidiaries) on the other, of the responsibilities, liabilities and benefits relating to any taxes for which a combined return is filed for taxable periods including or beginning on May 5, 2010. Subsequent to the PAA Ownership Transaction, income tax expense allocated to us under applicable allocation methodologies has not been material.

Relationship with our general partner

Except as previously disclosed, we are not party to any material transactions with our general partner or any of its affiliates. Additionally, our general partner is not obligated to provide any direct or indirect financial assistance to us or to increase or maintain its capital investment in us.

Table of Contents**Note 10 Equity Compensation Plans****Long Term Incentive Plan (LTIP)**

On April 27, 2010, PNGS GP LLC, the general partner of the Partnership, adopted the PAA Natural Gas Storage, L.P. 2010 Long Term Incentive Plan (the 2010 LTIP Plan) for the employees, directors and consultants of our general partner and its affiliates, including PAA, who perform services on our behalf. Although other types of awards are contemplated under the 2010 LTIP Plan, currently outstanding awards are limited to phantom units, which mature into the right to receive common units of PNG, or the equivalent cash value, upon vesting. The 2010 LTIP Plan limits the number of common units that may be delivered pursuant to awards under the plan to 3,000,000 units.

During the second quarter of 2010, 658,500 phantom units were granted under the 2010 LTIP Plan to directors, officers and other employees, a portion of which were granted upon conversion of outstanding awards denominated in common units of PAA. Of this total, (i) 30,000 phantom units will vest annually in 25.0% increments and have an automatic re-grant feature such that as they vest, an equivalent amount is granted; (ii) 326,000 phantom units will vest in one-third increments upon the later of (a) the May 2012 distribution date and the date we pay a quarterly distribution of at least \$0.3875, (b) the May 2013 distribution date and the date we pay a quarterly distribution of at least \$0.4500, and (c) the May 2014 distribution date and the date we pay a quarterly distribution of at least \$0.4750; and (iii) 302,500 phantom units will vest in 25.0% increments in connection with the conversion of our Series A subordinated units and the conversion of each of the first three tranches of our Series B subordinated units. Distribution equivalent rights were also awarded with respect to 342,500 of the phantom unit grants.

In November 2010, our Board of Directors approved the modification (subject to agreement by the individual award recipients) of 302,500 LTIP awards originally granted in the second quarter of 2010 to more closely align the vesting of these awards to the conversion of our Series B subordinated units as a result of the modification of our subordinated units in August 2010 (see Note 5). Such awards now vest in 20% increments in connection with the conversion of our Series A subordinated units and the conversion of each of the first four tranches of our Series B subordinated units. The impact of this modification was not material.

Our LTIP activity for awards issued under the 2010 LTIP Plan is summarized in the following table (in thousands, except per unit data):

	Units	Weighted Average Grant Date Fair Value per Unit
Outstanding, May 5, 2010		\$
Granted (1)	675	19.41
Vested	(2)	23.08
Cancelled or forfeited	(50)	19.22
Outstanding, December 31, 2010	623	\$ 19.42

(1) Includes 662,000 equity classified awards and 13,500 liability classified awards.

Prior to our initial public offering and adoption of the 2010 LTIP Plan, certain of our officers and other individuals providing direct services on our behalf were granted LTIP awards under LTIP plans sponsored by PAA's general partner (PAA LTIP Awards). Such awards, which allow settlement in cash or PAA common units upon vesting at the election of PAA's general partner, generally contained performance conditions based on the attainment of certain annualized PAA distribution levels or the attainment of specific PNG EBITDA levels and vested upon the later of a certain date or the attainment of such levels. In connection with the second quarter grants under the 2010 LTIP Plan, substantially all of the then outstanding liability-classified PAA LTIP awards held by PNG management were

converted to equity-classified PNG LTIP awards, which resulted in a reclassification to Partners' capital of approximately \$0.9 million of compensation expense recognized on such awards through the modification date. As of December 31, 2010, approximately 40,000 PAA LTIP awards are outstanding and unvested. We reimbursed PAA approximately \$1.1 million for PAA LTIP awards that vested during the twelve months ended December 31, 2010.

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The fair value of our liability classified awards is calculated based on the closing price of the underlying PAA or PNG units as of each balance sheet date and adjusted for the present value of any distributions that are estimated to occur on the underlying units over the service period that will not be received by the award recipients. The fair value of our equity classified awards is calculated based on the closing price of our common units as of the respective grant dates and adjusted for the present value of any distributions that are estimated to occur on the underlying units over the service period that will not be received by the award recipient. The fair value of these awards is recognized as compensation expense over the service period. For awards with performance conditions (such as distribution targets), expense is accrued over the service period only if the performance condition is considered to be probable of occurring. When awards with performance conditions that were previously considered improbable become probable, we incur additional expense in the period that our probability assessment changes. This is necessary to bring the accrued liability associated with these awards up to the level it would be as if we had been accruing for these awards since the grant date. Substantially all of our equity compensation expense is reflected as a component of general and administrative expenses in our accompanying consolidated statements of operations.

Our accrued liability at December 31, 2010 and December 31 2009 related to all outstanding liability classified LTIP awards is approximately \$1.0 million and \$1.8 million, respectively. Approximately \$0.6 million and \$0.7 million of such amounts were reflected in accounts payable and accrued liabilities in our accompanying consolidated balance sheets as of December 31, 2010 and December 31, 2009, respectively, with the remaining balances included as a component of other long-term liabilities at each respective date. We have also recognized \$2.7 million in Partners' capital related to all outstanding equity classified LTIP awards. Compensation expense recognized on 2010 LTIP Plan awards reflects our assessment that, as of December 31, 2010, an annualized PNG distribution of \$1.45 and the conversion of our Series A subordinated units and the first tranche of our Series B subordinated units are probable of occurring.

Class B Awards of Our General Partner

In July 2010, the Board of Directors of our general partner authorized the issuance of 165,000 Class B Units (PNGS Class B Units) of PNGS GP LLC (PNG's general partner) in order to create long term incentives for our management. The entire economic burden of the PNGS Class B Units, which are equity classified, will be borne solely by our general partner and will not impact our cash or our units outstanding. We will recognize the grant date fair value of the PNGS Class B Units as compensation expense over the service period, with such expense recognized as a capital contribution. We will not be obligated to reimburse our general partner for such costs and any distributions made on the PNGS Class B Units will not reduce the amount of cash available for distribution to our unitholders.

As of December 31, 2010, 90,750 PNGS Class B units were issued and outstanding. The PNGS Class B Units earn the right to participate in distributions (i.e. become earned) in 25% increments 180 days following the payment by PNG of quarterly distributions that equate to annualized distribution levels of \$2.00, \$2.30, \$2.50 and \$2.70. When PNGS Class B Units become earned units, they will participate in quarterly distributions paid to our general partner in excess of \$2.5 million. In addition, 50% of the applicable earned units vest immediately upon becoming earned units and the remaining 50% vest on the fifth anniversary of the date of grant. If PNGS Class B Units become earned units after the fifth anniversary of the date of grant, 100% of such units will vest immediately upon becoming earned units. Assuming all 165,000 PNGS Class B Units were granted and earned, the maximum participation rate would be 6% of PNG's quarterly general partner distribution in excess of \$2.5 million. No expense was recognized during the twelve months ended December 31, 2010 as it was not deemed probable that any of the performance conditions necessary for the PNGS Class B Units to become earned would be met.

Transaction/Transition Awards Granted by PAA

During September 2010, PAA entered into agreements with certain officers of PAA pursuant to which these individuals were granted approximately 375,000 awards denominated in PNG common units, Series A subordinated units, and Series B Subordinated units. The awards will vest upon the completion of the service period and certain performance conditions including the conversion of PNG's Series A subordinated units into common units of PNG and the conversion of PNG's Series B subordinated units into Series A subordinated units of PNG. Upon vesting, these awards will be settled with outstanding common or Series A subordinated units of PNG currently owned by PAA. The entire economic burden of these agreements will be borne solely by PAA and will not impact our cash or our units

outstanding. Since these individuals also serve as officers of PNG and PNG benefits as a result of the services they provide, we will recognize the grant date fair value of these awards as compensation expense over the service period, with such expense recognized as a capital contribution. During 2010, we recognized approximately \$1.5 million of expense and a corresponding capital contribution associated with these awards.

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Table of Contents**Other Consolidated Equity Compensation Information**

The table below summarizes the expense recognized and the value of vested awards related to our equity compensation plans (in thousands):

	Successor		Predecessor					
	Year ended		September 3, 2009 through		January 1, 2009 through		Year ended	
	December 31, 2010		December 31, 2009		September 2, 2009		December 31, 2008	
	Liability Awards	Equity Awards	Liability Awards	Equity Awards	Liability Awards	Equity Awards	Liability Awards	Equity Awards
Equity compensation expense	\$ 932	\$ 1,815	\$ 1,467	\$	\$ 304	\$	\$ (110)	\$
LTIP cash settled vestings	\$ 1,133	\$	\$ 383	\$	\$	\$	\$	\$
Distribution equivalent right payments	\$	\$ 16	\$	\$	\$	\$	\$	\$

Based on the December 31, 2010 fair value measurement and probability assessment regarding future distributions, we expect to recognize approximately \$7.5 million (which includes approximately \$5.0 million associated with the awards granted by PAA which we do not bear the economic burden of) of additional expense over the estimated service period of our outstanding awards related to the remaining unrecognized fair value. For our liability classified awards, this estimate is based on the fair value of the outstanding awards as of December 31, 2010. For our equity classified awards, this estimate is based on the grant date fair value of such awards. Actual amounts may materially differ as a result of a change in the market price of our units and/or probability assessment regarding future distributions. We estimate that the remaining fair value will be recognized in expense as shown below (in thousands):

Year	Equity Compensation Plan Fair Value Amortization ⁽¹⁾
2011	\$ 1,308
2012	766
2013	358
2014 and thereafter	113
Total	\$ 2,545

(1) Amounts do not include fair value associated with awards containing performance conditions that are not considered to be probable of occurring at December 31, 2010.

(2) Amounts do not include fair value associated with awards which are not dilutive to our limited partners or impact cash flow available for distribution to our limited partners.

Note 11 Commitments and Contingencies

In the ordinary course of doing business, we lease storage and pipeline transportation capacity from third parties and enter into purchase commitments in conjunction with our operations and our capital expansion program. In addition, we may enter into contracts related to construction costs associated with certain of our capital projects.

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The following table includes our best estimate of the amount and timing of the payments due under our contractual obligations as of December 31, 2010 (in thousands):

	Total	2011	2012	2013	2014	2015	Thereafter
Leases storage, transportation, other	\$37,691	\$14,176	\$10,723	\$6,216	\$4,462	\$2,009	\$ 105
Purchase obligations	35,318	18,057	1,866	1,866	1,866	1,866	9,797
Total	\$73,009	\$32,233	\$12,589	\$8,082	\$6,328	\$3,875	\$9,902

Expenditures related to leases for the year ended December 31, 2010, the period from September 3, 2009 to December 31, 2009, the period from January 1, 2009 to September 2, 2009, and the year ended December 31, 2008 were approximately \$17.4 million, \$3.1 million, \$7.3 million and \$5.9 million, respectively.

Environmental

We may experience releases of crude oil, natural gas, brine or other contaminants into the environment, or discover past releases that were previously unidentified. Although we maintain an inspection program designed to prevent and, as applicable, to detect and address such releases promptly, damages and liabilities incurred due to any such environmental releases from our assets may affect our business. As of December 31, 2010, we have not identified any material environmental obligations.

Litigation

We, in the ordinary course of business, are a claimant and/or a defendant in various legal proceedings. To the extent we are able to assess the likelihood of a negative outcome for these proceedings, our assessments of such likelihood range from remote to probable. If we determine that a negative outcome is probable and the amount of loss is reasonably estimable, we accrue the estimated amount. We do not believe that the outcome of these legal proceedings, individually or in the aggregate, will have a materially adverse effect on our financial condition, results of operations or cash flows.

Insurance

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. We maintain insurance of various types that we consider adequate to cover our operations and properties. The insurance covers our assets in amounts considered reasonable. The insurance policies are subject to deductibles that we consider reasonable and not excessive. 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 environmental 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 environmental 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 environmental 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.

Pine Prairie Project Sale and Lease

In May 2006, in order to receive a substantial tax exemption with respect to a portion of the Pine Prairie facility located in Evangeline Parish, Louisiana, we sold a portion of the facility located in the parish to the Industrial Development Board No. 1 of the Parish of Evangeline State of Louisiana, Inc. (the Industrial Development Board) and leased back the property. Simultaneously with the execution of the lease, the Industrial Development Board issued and sold \$50 million in bonds to us. Our rental obligations under the lease consist of an amount equal to the annual interest payment due from the Industrial Development Board on the bonds and the amount (if any) required for repayment in full of the outstanding

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indebtedness with respect to the bonds at the end of the lease term. Additionally, we are required to pay an annual \$15,000 administrative fee to the Industrial Development Board, as well as reasonable fees, expenses and charges of the trustee in connection with the bonds.

The lease has a 15-year term, which commenced in January 2008, and is terminable by us upon payment to the Industrial Development Board of the amount required for repayment in full of its outstanding indebtedness under the bonds. We also have an option to purchase the leased properties at any time during the lease term for the sum of \$5,000 plus the amount required for the repayment in full of any outstanding indebtedness under the bonds.

We will not be subject to ad valorem property tax in the Parish of Evangeline for the property included in this arrangement during the term of the lease except for ad valorem tax on inventory. We are required to make certain payments in lieu of ad valorem property taxes (PILOT Payments) beginning in 2010, calculated as the difference between \$500,000 and a three year average of ad valorem inventory tax revenues applicable to natural gas in the facility for the prior three consecutive calendar years. During 2010, we made our initial PILOT Payment of approximately \$0.2 million.

The passive ownership of the facilities by the Industrial Development Board will not result in any impact to the operation of the Pine Prairie facility. In addition, the tax exemption enables Pine Prairie to offer more competitively priced storage services to respond to market forces.

The lease also contains certain covenants that Pine Prairie must comply with in order to obtain the related ad valorem property tax benefits during the term of the lease including maintenance of a minimum level of employment at the facility. We are currently in compliance with the covenants in the lease. In addition to the PILOT Payments, we were also obligated to make an additional payment to retire a school bond previously issued by the Parish in an unrelated transaction. We paid approximately \$3.2 million in April 2008 in full satisfaction of this obligation. Amounts related to the revenue bond and lease obligation are presented on a net basis in our consolidated financial statements.

In conjunction with the PAA Ownership Transaction, this tax abatement agreement was valued at approximately \$23 million and is reflected as a component of goodwill and intangibles, net in our consolidated balance sheet.

Table of Contents**Note 12 Quarterly Financial Data (Unaudited):**

	First Quarter	Second Quarter	Successor Third Quarter	Fourth Quarter	Total ⁽¹⁾
	(in thousands, except per unit data)				
2010					
Revenues	\$22,205	\$24,158	\$25,083	\$28,841	\$100,287
Gross margin (2)	\$10,179	\$13,727	\$13,784	\$15,403	\$ 53,093
Operating income	\$ 6,165	\$ 9,987	\$10,375	\$10,601	\$ 37,128
Net income	\$ 3,123	\$ 7,232	\$ 9,620	\$ 9,812	\$ 29,787
Net income attributable to limited partners (3)(5)	\$	\$ 4,927	\$ 9,620	\$ 9,812	\$ 24,359
Basic net income per limited partner unit (3)(5)	\$	\$ 0.11	\$ 0.21	\$ 0.22	\$ 0.54
Diluted net income per limited partner unit (3)(5)	\$	\$ 0.11	\$ 0.21	\$ 0.22	\$ 0.54
Cash distributions per common unit (4)	\$	\$0.2114	\$0.3375	\$0.3450	\$ 0.8939

	Predecessor		Successor			
	First Quarter	Second Quarter	Third Quarter July 1 through September 2	September 3 through September 30	Fourth Quarter	
	Quarter	Quarter	2	30	Quarter	
					Total ⁽¹⁾	
2009						
Revenues	\$15,359	\$19,110	\$12,460	\$6,370	\$18,881	\$72,180
Gross margin (2)	\$ 5,855	\$10,435	\$ 7,157	\$3,531	\$ 7,304	\$34,282
Operating income	\$ 4,596	\$ 8,913	\$ 6,376	\$2,148	\$ 4,604	\$26,637
Net income	\$ 3,871	\$ 6,054	\$ 5,593	\$1,006	\$ 1,482	\$18,006

- (1) The sum of the four quarters may not equal the total year due to rounding.
- (2) Gross Margin is calculated as Total Revenues less (i) Storage related costs, (ii) Other operating costs, (iii) Fuel expense and (iv) Depreciation, depletion and amortization.
- (3) Excludes results attributable to the period prior to the closing of the Partnership's initial public offering on May 5, 2010.
- (4) Represents cash distribution per limited partner unit earned for the quarter which was declared and paid in the following quarter.
- (5) For all periods during 2010, our Series B subordinated units were not entitled to participate in earnings or distributions.

Note 13 Operating Segments

We manage our operations through two operating segments, Bluewater and Pine Prairie. We have aggregated these operating segments into one reporting segment, Gas Storage. Our Chief Operating Decision Maker (our Chief

Executive Officer) evaluates segment performance based on a variety of measures including adjusted EBITDA, volumes, adjusted EBITDA per thousand cubic feet (mcf) and maintenance capital investment. We have aggregated our two operating segments into one reportable segment based on the similarity of their economic and other characteristics, including the nature of services provided, methods of execution and delivery of services, types of customers served and regulatory requirements. 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 selected items that are generally unusual or non-recurring. The measure above excludes depreciation, depletion and amortization as we believe that depreciation, depletion and amortization are largely offset by repair and maintenance capital investments. Maintenance capital consists of expenditures for the replacement of partially or fully depreciated assets in order to maintain the operating capability, service capability, and/or functionality of our existing assets.

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The following table reflects certain financial data for our reporting segment for the periods indicated (in thousands):

	Successor		Predecessor	
	Year Ended December 31, 2010	September 3, 2009 through December 31, 2009	January 1, 2009 through September 2, 2009	Year Ended December 31, 2008
	(See Note 1)		(See Note 1)	
Revenues ⁽¹⁾	\$ 100,287	\$ 25,251	\$ 46,929	\$ 49,177
Adjusted EBITDA	\$ 53,857	\$ 12,165	\$ 28,701	\$ 31,001
Maintenance capital	\$ 438	\$ 320	\$ 384	\$ 377
Long-lived assets ^{(1), (2)}	\$ 962,852	\$ 888,164		\$ 757,588
Total assets ⁽²⁾	\$ 998,728	\$ 900,407		\$ 811,436

⁽¹⁾ We only have operations in the United States, thus no geographic data disclosure is necessary for revenues or long-lived assets.

⁽²⁾ Amounts are as of December 31.

The following table reconciles Adjusted EBITDA to consolidated net income (in thousands):

	Successor		Predecessor	
	Year Ended December 31, 2010	September 3, 2009 through December 31, 2009	January 1, 2009 through September 2, 2009	Year Ended December 31, 2008
	(See Note 1)		(See Note 1)	
Adjusted EBITDA	\$ 53,857	\$ 12,165	\$ 28,701	\$ 31,001
Selected items impacting Adjusted EBITDA:				
Equity compensation expense	(2,747)	(1,467)	(304)	110
Acquisition related costs	(251)			
Mark-to-market of open derivative positions	370	(370)		548
Depreciation, depletion and amortization	(14,119)	(3,578)	(8,054)	(6,245)
Interest expense, net of amounts capitalized	(7,323)	(4,262)	(4,352)	(4,941)
Income tax expense			(473)	(887)
Net Income	\$ 29,787	\$ 2,488	\$ 15,518	\$ 19,586

Note 14 Subsequent Events

Bluewater Incident

In January 2011, an incident and fire occurred at our Bluewater Natural Gas Storage facility. The cause of the incident remains under review and receipt of necessary regulatory approvals and permits will be necessary to restore the facility to full operation. We expect that the incident will be covered by property damage insurance, subject to a \$500,000 deductible, and, if necessary, business interruption insurance after 45 days. We do not believe that this event will have a material long-term impact on our financial position, results of operations or cash flows.

Southern Pines Acquisition

In February 2011, we completed the acquisition of SG Resources Mississippi, LLC from SGR Holdings, L.L.C. for consideration of approximately \$746 million, subject to certain post closing adjustments. The primary asset of SG Resources

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is the Southern Pines Energy Center (Southern Pines), a FERC-regulated, salt-cavern natural gas storage facility located in Greene County, Mississippi. Southern Pines is permitted for 40 Bcf of working gas capacity from four storage caverns.

We obtained financing of approximately \$800 million to fund the purchase price, closing costs and first 18 months of expansion capital associated with this acquisition. In conjunction with closing of this acquisition, we borrowed \$200 million bearing interest at 5.25% under a three-year financing arrangement with PAA and we issued approximately 27.6 million additional common units, of which approximately 17.4 million were sold to third-party investors and the remainder were sold to PAA. As a result of these common units issuances, PAA's aggregate equity ownership of us is approximately 64%. Third-party investors were issued certain rights relating to the registration of the common units purchased.

Sale of Land for PAA Natural Gas Processing Plant

In January of 2011, we sold an approximately 30 acre parcel of vacant, unused land located in Acadia Parish, Louisiana to a subsidiary of PAA to be used for the potential development of a natural gas processing plant. The sales price of approximately \$72,000 was based on a third party appraisal and the sale was made on an as is, where is basis without any representations or warranties by us.

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EXHIBIT INDEX

- 2.1 Purchase and Sale Agreement dated December 28, 2010 by and among SGR Holdings, L.L.C., Southern Pines Energy Investment Co., LLC and PAA Natural Gas Storage, L.P. (incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K filed on December 30, 2010).
- 3.1 Certificate of Limited Partnership of PAA Natural Gas Storage, L.P. (incorporated by reference to Exhibit 3.1 to the Registration Statement on Form S-1 (333-164492) filed on January 25, 2010).
- 3.2 Second Amended and Restated Agreement of Limited Partnership of PAA Natural Gas Storage, L.P. dated August 16, 2010 (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed on August 20, 2010).
- 3.3 Certificate of Formation of PNGS GP LLC (incorporated by reference to Exhibit 3.3 to the Registration Statement on Form S-1 (333-164492) filed on January 25, 2010).
- 3.4 Amended and Restated Limited Liability Company Agreement of PNGS GP LLC dated May 5, 2010 (incorporated by reference to Exhibit 3.4 to the Quarterly Report on Form 10-Q filed on August 6, 2010).
- 4.1 Form of Registration Rights Agreement by and among PAA Natural Gas Storage, L.P. and the purchasers party thereto (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed on December 30, 2010).
- 4.2 Form of Registration Rights Agreement by and among PAA Natural Gas Storage, L.P. and the purchasers party thereto (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed on January 20, 2011).
- 10.1 Contribution Agreement dated as of April 29, 2010 by and among PAA Natural Gas Storage, L.P., PNGS GP LLC, Plains All American Pipeline, L.P., PAA Natural Gas Storage, LLC, PAA/Vulcan Gas Storage, LLC, Plains Marketing, L.P. and Plains Marketing GP Inc. (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed on May 4, 2010).
- 10.2 Omnibus Agreement dated May 5, 2010 by and among Plains All American GP LLC, Plains All American Pipeline, L.P., PNGS GP LLC and PAA Natural Gas Storage, L.P. (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed on May 11, 2010).
- 10.3 Tax Sharing Agreement dated May 5, 2010 by and among Plains All American Pipeline, L.P. and PAA Natural Gas Storage, L.P. (incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K filed on May 11, 2010).
- 10.4 Credit Agreement dated April 7, 2010 among PAA Natural Gas Storage, L.P., Bank of America, N.A., DnB Nor Bank ASA, Wells Fargo Bank, National Association, UBS Loan Finance LLC and Citibank, N.A. and the other lenders party thereto (incorporated by reference to Exhibit 10.4 to the Current Report on Form 8-K filed May 11, 2010).
- 10.5 Employment Agreement, effective November 1, 2008, between Dean Liollo and Plains All American GP LLC (incorporated by reference to Exhibit 10.10 to Amendment No. 3 to the Registration Statement on Form S-1 (333-164492) filed on April 13, 2010).

- 10.6 Employment Agreement, effective September 15, 2009, between Richard McGee and Plains All American GP LLC (incorporated by reference to Exhibit 10.9 to Amendment No. 3 to the Registration Statement on Form S-1 (333-164492) filed on April 13, 2010).
 - 10.7 PAA Natural Gas Storage, L.P. 2010 Long Term Incentive Plan (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed on May 11, 2010).
 - 10.8 Form of Phantom Unit and Distribution Equivalent Right Grant Letter (incorporated by reference to Exhibit 10.4 to Amendment No. 3 to the Registration Statement on Form S-1 (333-164492) filed on April 13, 2010).
 - 10.9 Form of Phantom Unit Grant Letter (incorporated by reference to Exhibit 10.9 to the Quarterly Report on Form 10-Q filed on November 5, 2010).
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- 10.10 Form of PNGS GP LLC Class B Restricted Unit Agreement (incorporated by reference to Exhibit 10.10 to the Quarterly Report on Form 10-Q filed on August 6, 2010).
- 10.11 Common Unit Purchase Agreement dated December 23, 2010 by and among PAA Natural Gas Storage, L.P. and the purchasers party thereto (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed on December 30, 2010).
- 10.12 Common Unit Purchase Agreement dated January 19, 2011 by and among PAA Natural Gas Storage, L.P. and the purchasers party thereto (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed on January 20, 2011).
- 10.13 Note Payable to PAA dated February 9, 2011 (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed on February 14, 2011).
- 10.14 Agreement to Lease with Option to Purchase, dated May 1, 2006, between Industrial Development Board No. 1 of the Parish of Evangeline State of Louisiana, Inc. and Pine Prairie Energy Center, LLC (incorporated by reference to Exhibit 10.7 to Amendment No. 2 to the Registration Statement on Form S-1 (333-164492) filed on April 2, 2010).
- 10.15 * Director Compensation Summary
- 21.1* List of Subsidiaries of PAA Natural Gas Storage, L.P.
- 23.1* Consent of PricewaterhouseCoopers LLP.
- 23.2* Consent of PricewaterhouseCoopers LLP.
- 31.1* Certification of Principal Executive Officer pursuant to Exchange Act Rules 13a-14(a) and 15d-14(a).
- 31.2* Certification of Principal Financial Officer pursuant to Exchange Act Rules 13a-14(a) and 15d-14(a).
- 32.1* Certification of Principal Executive Officer pursuant to 18 U.S.C. 1350.
- 32.2* Certification of Principal Financial Officer pursuant to 18 U.S.C. 1350.

Management compensatory plan or arrangement.

* Filed herewith.